NYCA INSTALLED CAPACITY REQUIREMENT FOR THE PERIOD MAY 2006 THROUGH APRIL 2007

ADDENDUM TO THE JANUARY 31, 2006 REPORT

AND

JANUARY 31, 2006 REPORT

New York State Reliability Council, L.L.C.

May 12, 2006

Addendum
to the NYSRC Technical Study Report
"NYCA Installed Capacity Requirement for the Period May 2006 through April 2007"

On January 31, 2006, the Executive Committee of the New York State Reliability Council (NYSRC) adopted an 18.0% New York Control Area (NYCA) Installed Reserve Margin (IRM) requirement for the Capability Year from May 1, 2006 through April 30, 2007. This decision was based on IRM study results in the NYSRC report, *"NYCA Installed Capacity Requirement for the Period May 2006 through April 2007"* (2006 IRM Report), dated January 31, 2006. The 2006 IRM Report follows this Addendum.

On March 10, 2006 the New York Independent System Operator (NYISO) informed the NYSRC that errors had been discovered in the General Electric Multi-Area Reliability Simulation (GE-MARS) data base for the above technical study that was relied on by the NYSRC for its adoption of the 18.0% IRM. The data base that was used to calculate the previous statewide IRM had incorrectly modeled locational operating reserves. This was caused by incorrectly applying on a zonal basis, emergency operating procedures -- resulting in a capacity shift from the New York City (NYC) and Long Island (LI) zones to Western New York zones.

The NYISO corrected these data base errors, reran the study, and provided the NYSRC with updated 2006-2007 IRM study results. The updated study also used the latest NYCA load forecast, which had been used by the NYISO in setting the original LCRs. All other study assumptions remain unchanged from those used in the 2006 IRM Study. Due to time and resource limitations, sensitivity cases were not prepared for the updated study.

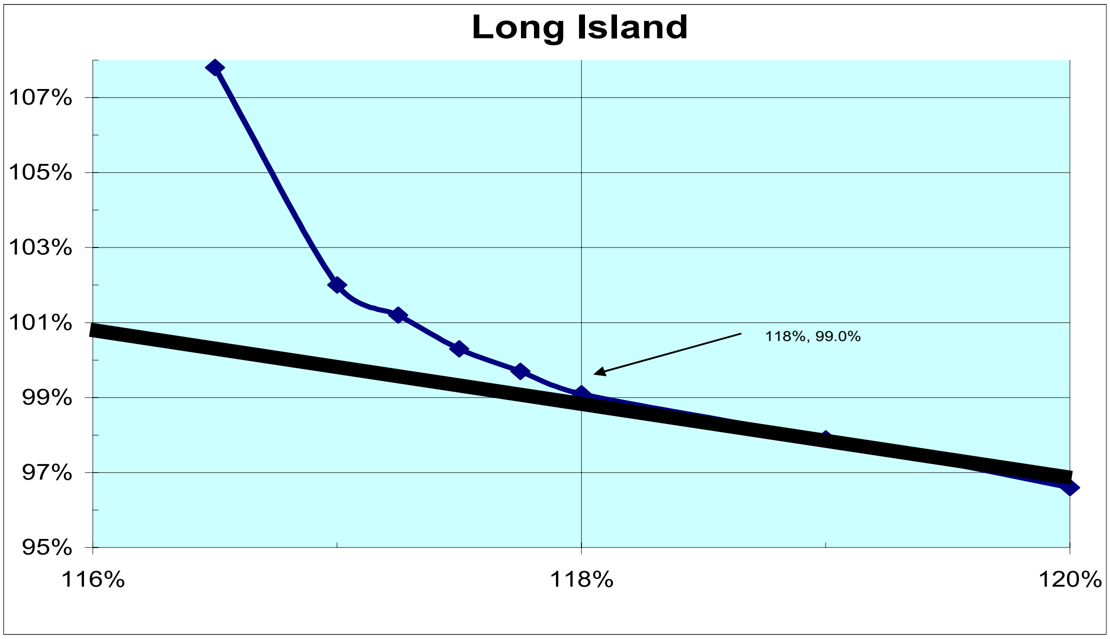
The Unified Method as described under "Study Procedure" in the 2006 IRM Report was used to develop updated study results, which was the basis for curves in the attached Figure A. Figure A depicts the relationship between NYCA IRM Requirements and resource capacity in NYC and LI. The IRM Anchoring Method, also described under "Study Procedure", provided TAN 45 anchor points on the Figure A curves from which the base case IRM was evaluated. The use of the corrected data base eliminated an understatement of downstate capacity which resulted in a change in the curves in Figure 2 of the January 31, 2006 report to the curves depicted in Figure A.

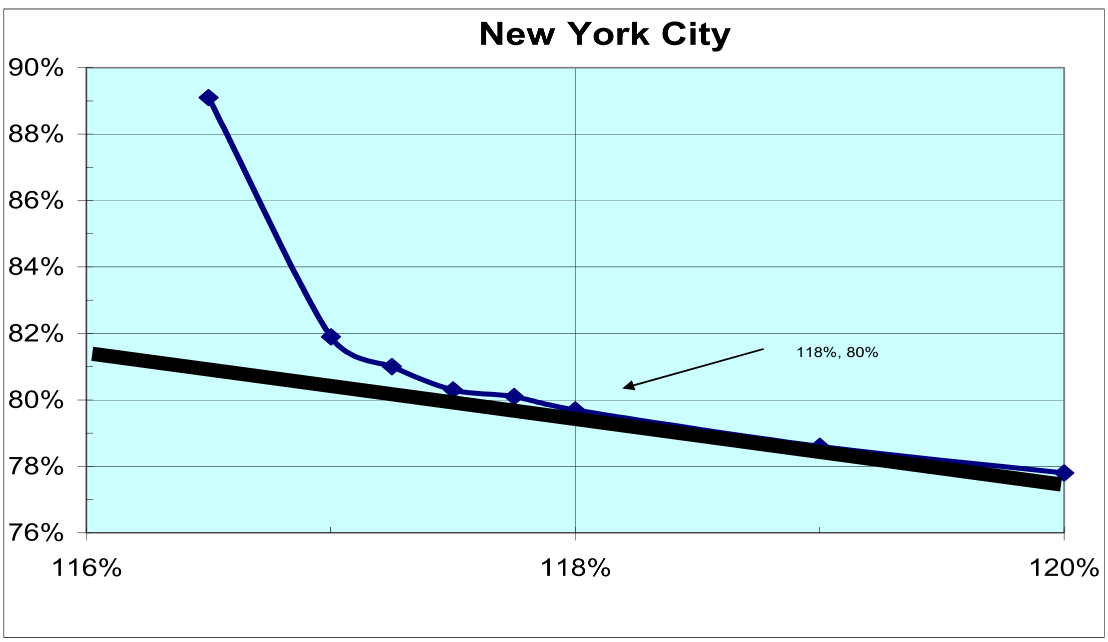
From these updated curves it was concluded that using the corrected data base, as well as the latest load forecast, results in the NYCA base case IRM requirement remaining at 18.0%. Although the TAN 45 anchor point remained at 18.0% IRM - the same as depicted on Figure 2 - the anchor point minimum LCRs were reduced to those shown in Figure A, as described below. On March 20, 2006, the NYSRC Executive Committee reaffirmed the 18.0% for the NYCA IRM for the 2006-2007 Capability Year.

As was the case with the IRM Study, the NYISO's Locational Capacity Requirement (LCR) Study was rerun by the NYISO in March 2006 using the same updated data base and Unified and IRM Anchoring Methods as used for the IRM Study. The updated LCR study, approved by the NYISO Operating Committee on March 28, 2006, resulted in the lowering of the NYISO's February 2006 LCR study results from 82.5% / 106.0% to 80.0% / 99.0% for New York City and Long Island, respectively. The updated NYISO LCR study is described in the NYISO report, *"Revised Locational Capacity Requirement Study Covering the NYCA for the 2006-2007 Capability Year",* dated March 28, 2006 (This NYISO report can be found on the NYISO Web site, www.nyiso.com .)

Figure A

NYCA Locational ICAP Requirements vs. Statewide ICAP Requirements UDR Base Case





NEW YORK CONTROL AREA INSTALLED CAPACITY REQUIREMENTS FOR THE PERIOD MAY 2006 THROUGH APRIL 2007

New York State Reliability Council, L.L.C.

Executive Committee Resolution
And
Technical Study Report

January 31, 2006

NEW YORK STATE RELIABILITY COUNCIL, L.L.C.

APPROVAL OF NEW YORK CONTROL AREA INSTALLED CAPACITY REQUIREMENT FOR THE PERIOD MAY 1, 2006 THROUGH APRIL 30, 2007

1. WHEREAS, reliable electric service is critical to the economic and social welfare of the millions of residents and businesses in the State of New York; and

2. WHEREAS, the reliable and efficient operation of the New York State (NYS) Power System is fundamental to achieving and maintaining reliability of power supply; and

3. WHEREAS, The New York State Reliability Council, L.L.C.'s (NYSRC) principal mission is to establish Reliability Rules for use by the New York Independent System Operator (NYISO) to maintain the integrity and reliability of the NYS Power System; and

4. WHEREAS, the NYSRC is responsible for determining the New York Control Area (NYCA) annual Installed Capacity Requirement; and

5. WHEREAS, the study results in the Technical Study Report, dated January 31, 2006, conducted by the NYSRC Installed Capacity Subcommittee, show that the required NYCA installed reserve margin (IRM) for the May 1, 2006 through April 30, 2007 capability year is 18.0% under base case conditions, including the modeling of the Cross Sound Cable as 330 MW of Unforced Capacity Deliverability Rights (UDR); and

6. WHEREAS, in light of the Technical Study report, the modeling and assumption changes made to simulate actual operating conditions and system performance, the numerous sensitivity studies evaluated, and with due recognition that the current NYCA IRM is set at 18.0%;

7. NOW, THEREFORE BE IT RESOLVED, that in consideration of the factors addressed above, the NYSRC sets the NYCA IRM requirement at 18.0% for the May 1, 2006 through April 30, 2007 capability year, which equates to an Installed Capacity Requirement of 1.18 times the forecasted NYCA 2006 peak load.

NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENTS
FOR THE PERIOD
MAY 2006 THROUGH APRIL 2007

TECHNICAL STUDY REPORT

January 31, 2006
New York State Reliability Council, LLC
Installed Capacity Subcommittee

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INTRODUCTION

Section 3.03 of the New York State Reliability Council (NYSRC) Agreement states that the NYSRC shall establish the annual statewide Installed Capacity Requirements (ICR) for the New York Control Area (NYCA) consistent with North American Electric Reliability Council (NERC) and Northeast Power Coordinating Council (NPCC) standards. This report describes a technical study conducted by the NYSRC Installed Capacity Subcommittee (ICS) for establishing the NYCA required installed reserve margin (IRM) for the period of May 2006 through April 2007 (Year 2006) in compliance with the NYSRC Agreement. The NYSRC Executive Committee will consider these study results. along with other factors, to establish the Final NYCA IRM Requirement for 2006-07.

The ICR relates to the IRM through the following equation:

$$\text{ICR} = (1 + \text{IRM\%} / 100) \times \text{Forecasted NYCA Peak Load}$$

The New York Independent System Operator (NYISO) will implement the statewide ICR as determined by the NYSRC — in accordance with the NYSRC Reliability Rules and the "NYISO Installed Capacity" manual. The NYISO translates the required IRM to an "Unforced Capacity" (UCAP) basis, in accordance with a 2001 NYISO filing to FERC. Also, in June 2003 the NYISO replaced its monthly Deficiency Auction with a Spot Market Auction based on FERC approved "Demand Curves." These Unforced Capacity and Demand Curve concepts are described later in the report.

This Year 2006 IRM Requirement Study implemented two new study methodologies. In 2005, the NYSRC and the NYISO staff undertook a joint study to enhance technical study procedures for establishing NYCA IRM Requirements and Locational Capacity Requirements (LCR). The joint study produced these methodologies:

1. The ***Unified Method*** is utilized by both the NYSRC and NYISO for the analysis of IRM Requirements (a NYSRC responsibility), and Locational Capacity Requirements (LCR), (a NYISO responsibility), and

2. The ***IRM Anchoring Method*** determines a consistent *anchor point* on IRM/LCR curves produced by the Unified Method, identifies both the NYCA IRM Requirement and corresponding Minimum Locational Capacity Requirements (MLCR). Following the NYSRC IRM Requirement study the NYISO, in its role of setting the appropriate LCR, beginning this year, will consider the MLCR determined by the NYSRC IRM Requirement study.

Both methodologies are discussed in more detail under "Study Procedure".

In December 2005, soon after completion of the Base Case and related sensitivity cases associated with the Year 2006 Study, the Long Island Power Authority (LIPA) announced its intention to utilize the full 330 MW of Unforced Capacity Deliverability Rights (UDR) associated with the Cross Sound Cable (CSC) transmission project. Modeling of CSC with UDR has an impact on NYCA IRM requirements. Accordingly, the NYSRC Executive

Committee approved a motion at its January 13, 2006 meeting to supplant the previously completed base case (referred to in this report as the "Non-UDR Case") with a new Base Case which models the Cross Sound Cable as a UDR (referred to as the "UDR Base Case"). This report includes an explanation of UDR and how it was applied in the Year 2006 Study.

Definitions of certain terms in this report can be found in the NYSRC Glossary in the *NYSRC Reliability Rules for Planning and Operating the New York State Power System*, http://www.nysrc.org/documents.html.

EXECUTIVE SUMMARY

Two cases for the Year 2006 were evaluated, with and without the designation of UDRs for the Cross Sound Cable. All other study assumptions were identical for both cases. **NYCA IRM requirements** were calculated as follows:

Non-UDR Case	**17.5%**
UDR Base Case	**18.0%**

For these cases the study also determined MLCRs of 82.0% and 99.5% for New York City (NYC) and Long Island (LI), respectively, for the Non-UDR Case; and MLCR of 82.5% and 106.0% for NYC and LI, respectively, for the UDR Base Case.

The inclusion of MLCR for the first time as part of the NYSRC IRM Requirement Study was the result of applying new study methodologies adopted by the NYSRC Executive Committee during 2005; the *Unified* and *IRM Anchoring Methods,* are described under "Study Procedure" The NYISO will consider the MLCR in its evaluation of the 2006-07 LCR for NYC and LI.

The study also evaluated IRM requirement impacts caused by the updating of key study assumptions and various sensitivity cases. These results are depicted in Tables 1 and 2 and in Appendix B-1. When taken together, the UDR Base Case, sensitivity and non-UDR case results, and other relevant factors provide the basis for a NYSRC Executive Committee establishment of the Final NYCA IRM Requirement for Year 2006.

There are several parameters and modeling enhancements that influenced the results of the Year 2006 Study. They are addressed in more detail under "Base Case Study Results".

1. ***Interconnection Support during Emergencies***. The Year 2006 Study introduced multi-area representation of two interconnected regional Control Areas, ISO New England (ISO-NE)1 and PJM Interconnection[2]. This type of representation captures

1 ISO-NE is now a Regional Transmission Organization (RTO)
2 As of January 1, 2006, Reliability First Corporation (RFC) is the new regional reliability organization that

the impact of internal transmission constraints within these Outside Areas on their ability to provide NYCA with emergency assistance.

2. ***Peak Load Forecast***. The peak load forecast used for the Year 2006 Study revealed a greater share of total NYCA load for the Downstate NY area than in previous studies. This factor increases the 2006 IRM Requirement.

3. ***Resource Capacity Availability***. The Year 2005 Study had introduced a Dependable Maximum Net Capability (DMNC) adjustment to account for the overstatement of resource capacity availability in outage data reporting to the NYISO. This 2006 Study used a 125 MW adjustment based on a NYISO analysis, down from the 711 MW adjustment used in the 2005 Study. This reduction was facilitated by several NYISO initiatives to mitigate capacity availability reporting overstatements.

4. ***NYCA Transmission Constraints***. In 2005 the NYSRC and NYISO jointly developed modeling and study methodology enhancements for considering the impact of transmission constraints and locational capacity on IRM Requirements. Accordingly, this Year 2006 Study implemented a new method, previously described, for "anchoring" and establishing a MLCR to ensure the NYCA IRM requirement will meet NYSRC Reliability Rules.

   Concerning the Lower Hudson Valley, the ability to transfer sufficient power into Downstate NY[3] to meet reliability criteria has been reduced due to: 1) continued load growth in this area, 2) changes in neighboring systems, and 3) changes in the transmission system network, such as the addition of the series reactors in the NYC cable system. The NYISO has determined that transfer limits will be reduced to meet voltage criteria.[4] To recognize voltage-limited transfers, this year's IRM Requirement study included a dynamic transfer limit model utilizing a nomogram which varies transfer limits as a function of the availability of designated generating units. This model is described in detail in Appendix A.

   Limitations across the Northport-Norwalk Harbor cable were modeled as a function of the availability of Norwalk Harbor generation. Limitations across the Con Edison Hudson-Farragut and Linden-Goethals lines were modeled as a function of the availability of Northern New Jersey generation such as Linden, Bergen, and Hudson.

5. ***Unforced Capacity Deliverability Rights (UDR).*** The UDR Base Case assumes utilization by LIPA of the full 330 MW of UDRs associated with the Cross Sound Cable project. The Year 2006 Study shows that implementing this option increases NYCA IRM requirements by 0.5 percentage points over the Non-UDR Case.

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includes PJM. The new RFC footprint includes the former MAAC, ECAR, and MAIN Reliability Councils.

3 For purposes of this study, Upstate NY is defined as the region that includes NYCA Zones A through I and Downstate NY refers to NYCA Zones J and K.

4 See NYISO draft report "Comprehensive Reliability Planning Process Reliability Needs Assessment", dated 11/25/05.

UDRs are capacity rights that allow the holder/owner to extract the Locational Capacity Benefit derived by the NYCA from the addition of a new incremental controllable transmission project that provides a transmission interface to a NYCA locality or zone. Non-locational capacity when coupled with a UDR can be used to satisfy locational capacity requirements. When transmission facilities are built in the NYCA, the NYSRC and NYISO conduct studies to determine the incremental reliability benefits associated with the project. The owner/holder of these UDR facility rights must designate how they will be treated by the NYSRC & NYISO during the development of the NYCA IRM and LCR studies. The NYISO calculates the actual UDR award based on the transfer capability of the facility and other data. The Cross Sound Cable, with a transfer capability of 330 MW, is the only existing project that is currently eligible for these awards. LIPA currently has the option on an annual basis of selecting the MW quantity of UDRs (ICAP) it plans on utilizing for capacity contracts over the Cross Sound Cable with any remaining capability being on the cable to be used to support emergency assistance and counted towards reducing the Locational and Installed Reserve Margin Requirements. LIPA has recently announced it has chosen the option of utilizing all of the CSC UDRs it is awarded by the NYISO. This is the basis for the UDR Base Case.

There are important issues to be considered in the use of the General Electric Multi-Area Reliability Simulation (GE-MARS) program for IRM studies with respect to the confidence of study results. An error analysis for this study showed that there is a 99.7% probability that the UDR Base Case IRM result is within a range of 17.6% to 18.5%. Within this range, the statistical significance of the 17.6%, 18.0%, and 18.5% numbers are a 0.15%, 50% and 99.85% probability of meeting the one day in ten criterion, assuming perfect accuracy in all parameters. Appendix A contains a detailed discussion of these issues.

STUDY PROCEDURE

This study utilizes a *probabilistic* approach for determining the NYCA IRM requirements. This technique calculates the probabilities of generating unit outages, in conjunction with load and transmission representations, to determine the days per year of expected capacity shortages.

GE-MARS is the primary analytical tool used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for the eleven NYCA Zones — plus four external Control Areas (Outside World Areas) directly interconnected to the NYCA. GE-MARS calculates "Loss of Load Expectation" (LOLE, expressed in days per year), to provide a consistent measure of system reliability.

This Year 2006 IRM Requirement Study applied two new study methodologies, the *Unified Method* and the *IRM Anchoring Method.* Both methodologies were developed jointly by the NYSRC and NYISO staff and adopted by the NYSRC Executive Committee in 2005.

- ***The Unified Method***

  Since the NYCA has had excess capacity in the past, previous NYSRC IRM Requirement study methodologies had included a procedure under which load was added in all NYCA zones until the loss of load expectation met criteria. LCR, however, has been separately determined by the NYISO around the peak load forecast for the localities being studied. This difference in the NYSRC and NYISO methodologies led the NYSRC ICS and the NYISO Staff to jointly pursue a more coordinated, "unified" approach to developing the relationship between the LCRs and IRM. This "Unified Method" establishes a graphical relationship between NYCA IRM and the LCRs, as depicted in Figure 1 under "Base Case Study Results". Appendix A describes this methodology in more detail.

  Briefly, capacity is removed from zones west of the Central-East interface that have excess capacity when compared to their forecast peaks until a study point IRM is reached. At this point, capacity is shifted from Zones J and K into the same zones as above until the 0.1 LOLE criterion is violated. Doing this at various IRM points yields a curve such as depicted in Figure 1, whereby all points on the curve meet the NYSRC 0.1 days/year LOLE criterion. Furthermore, all LCR "point pairs" for NYC and LI curves along the IRM axis represent a 0.1 LOLE solution for NYCA.

- ***The IRM Anchoring Method***

  This method establishes NYCA IRM Requirements and related MLCR from IRM/LCR curves established by the Unified Method. The *anchor point* on the curve in Figure 1 is selected by applying a tangent of 45 degrees ("Tan 45") analysis at the bend (or "knee") of the curve. Points on the curve on either side of the "Tan 45" point may create disproportionate changes in LCR and ICR, since small changes in LCR can introduce larger changes in IRM Requirements and vice versa.

Appendix A includes details of the reliability calculation process, information about the GE-MARS program, modeling parameters, and other assumptions.

Sensitivity analyses were also performed to determine variations to the Base Case IRM requirement. These analyses are used in conjunction with Base Case results to form the basis for the final NYCA IRM Requirement established by the NYSRC. Base Case study results and the sensitivity analyses are presented in **Appendix B**.

NYSRC RESOURCE ADEQUACY RELIABILITY CRITERIA

The acceptable LOLE reliability level used for establishing NYCA IRM Requirements is dictated by the NYSRC Reliability Rules, wherein Rule A-R1, *Statewide Installed Reserve Margin Requirements,* states:

The NYSRC shall establish the IRM requirement for the NYCA such that the probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System transfer capability, and capacity and/or load relief from available operating procedures.

This NYSRC Reliability Rule is consistent with the NPCC Resource Adequacy Standard in NPCC Document A-2.

In accordance with NYSRC Rule A-R2, *Load Serving Entity (LSE) Installed Capacity Requirements*, the NYISO is required to establish LSE installed capacity requirements, including locational capacity requirements, in order to meet the statewide IRM requirements established by the NYSRC for maintaining NYSRC Rule A-R1 above.

The NYSRC Reliability Rules can be found on the NYSRC Web site, www.nysrc.org.

NON-UDR CASE AND UDR BASE CASE STUDY RESULTS

Two Year 2006 cases were evaluated, with and without the designation of UDRs for the Cross Sound Cable. All other assumptions were identical in both cases. The results of these cases are as follows:

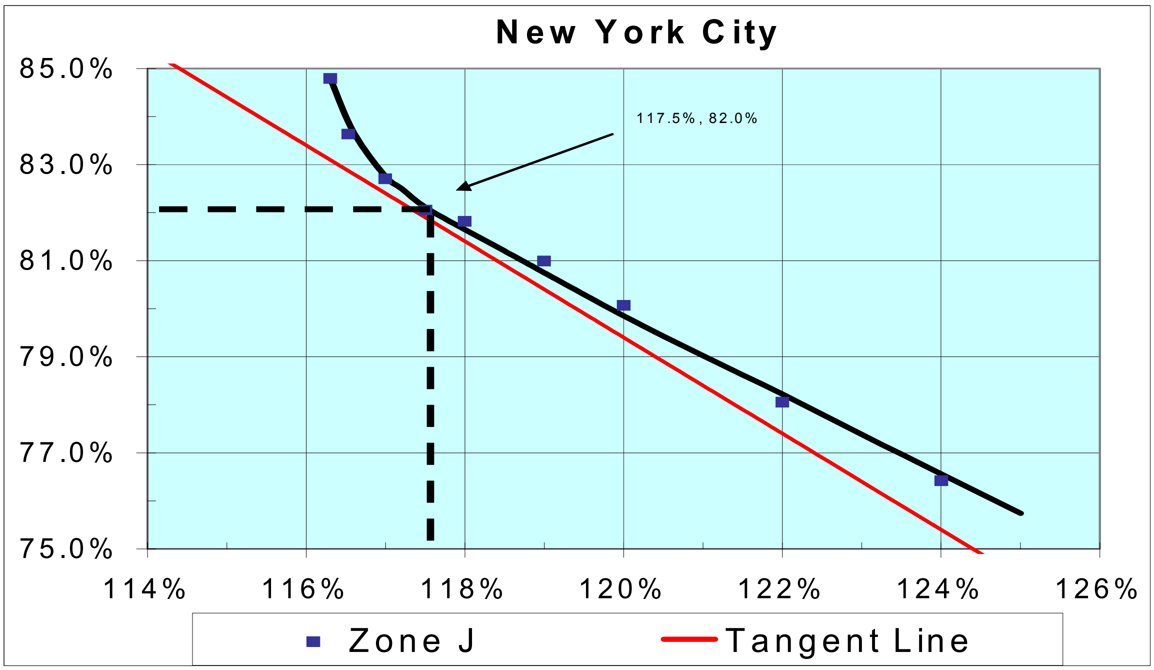
Non-UDR Case

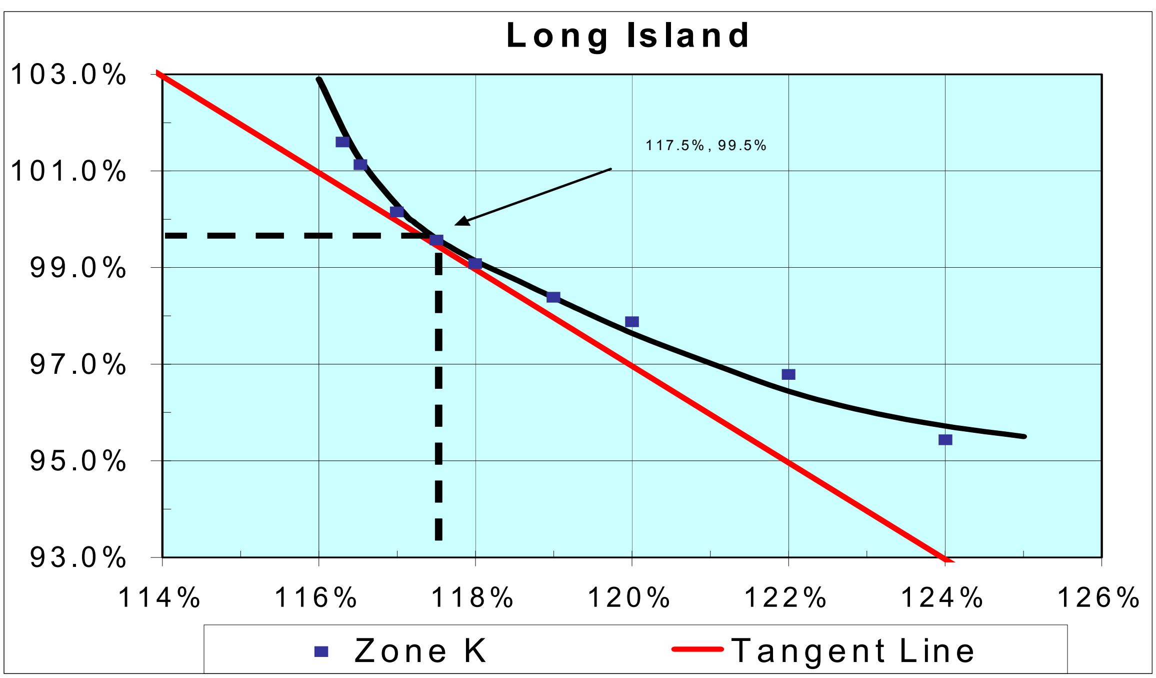
Year 2006 IRM study results for the **Non-UDR Case show a required NYCA IRM of 17.5%**. The study further showed corresponding MLCRs for NYC and LI of 82.0% and 99.5%**,** respectively. The new study methodologies described under "Study Procedure" were used to develop the curves in Figure 1, and from which these Non-UDR Case IRM Requirement and MLCR results were derived.

Figure 1 depicts the relationship between NYCA IRM Requirements and resource capacity in NYC and LI. The anchor points on these curves, from which these study results are based, were evaluated using the "Tan 45" analysis. Accordingly, we conclude that maintaining the NYCA installed reserve of 17.5% over the forecasted NYCA 2006 summer peak season, together with MLCR of 82.0% and 99.5% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the Base Case study assumptions shown in Appendix A.

Figure 1

NYCA Locational ICAP Requirements vs. Statewide ICAP Requirements Non-UDR Case





UDR Base Case

The UDR Base Case assumes the designation by LIPA of UDRs for the Cross Sound Cable (CSC) project.

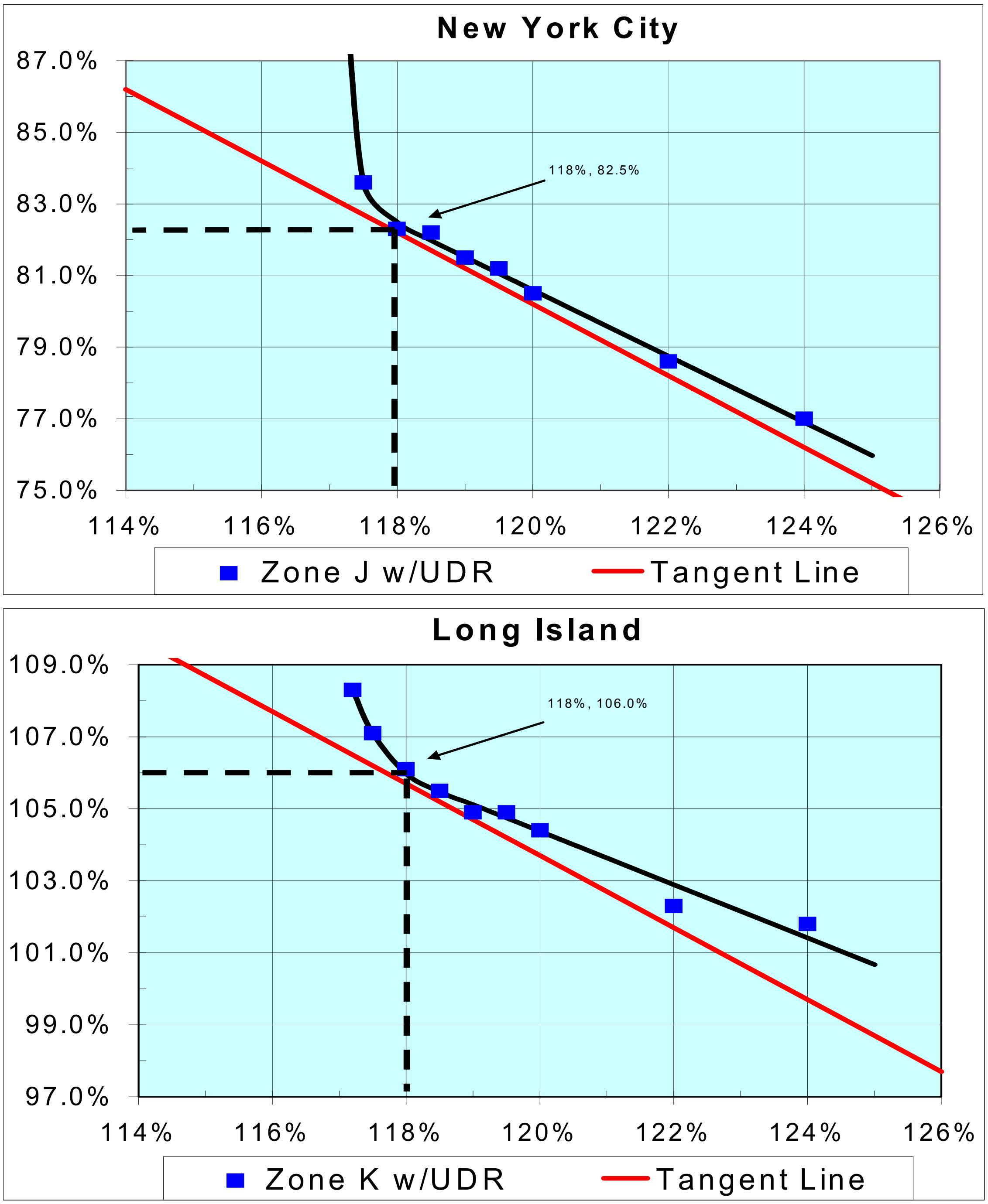
UDR's are capacity rights that allow the holder to extract the Locational Capacity Benefit derived by the NYCA from the addition of a new transmission incremental controllable transmission project that provides a transmission interface to a NYCA locality or zone. Non-locational capacity when coupled with a UDR can be used to satisfy locational capacity requirements. When transmission facilities are built in the New York Control Area (NYCA), the NYSRC and NYISO conduct studies to determine the incremental reliability benefits associated with the project. The owner/holder of these UDRs must designate how they will be treated by the NYSRC & NYISO during the development of the NYCA IRM and LCR studies. This selection process occurs on an annual basis, nominally prior to August 1st of each calendar year. The CSC, with a transfer capability of 330 MW, is the only existing project that is currently eligible for these awards. LIPA currently has the option on an annual basis of selecting the MW quantity of UDRs (ICAP) it plans on utilizing for capacity contracts over the CSC with any remaining capability on the cable being used to support emergency assistance and counted towards reducing the Locational and Installed Reserve Margin Requirements. LIPA has recently announced it has chosen the option of utilizing all of the CSC UDRs it is awarded by the NYISO. This is the basis for the UDR Base Case.

Year 2006 IRM study for the **UDR Base Case resulted in a required NYCA IRM of 18.0%**. The study further showed corresponding MLCRs for NYC and LI of 82.5% and 106.0%, respectively. As with the Non-UDR Case, the new study methodologies described under "Study Procedure" were used to develop the curves in Figure 2, and from which this UDR Base Case IRM Requirement and MLCR results were derived.

Figure 2 depicts the relationship between NYCA IRM Requirements and resource capacity in NYC and LI. The anchor points on these curves, from which these study results are based, were evaluated using the "Tan 45 analysis". It is the general agreement of the ICS that the tan 45 intersection of the smoothed curves occur at 118% for both NYC and LI. Accordingly, it is the judgment of the ICS that maintaining the NYCA installed reserve of 18.0% over the forecasted NYCA 2006 summer peak season, together with MLCR of 82.5% and 106.0% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the UDR Base Case study assumptions shown in Appendix A.

Figure 2

NYCA Locational ICAP Requirements vs. Statewide ICAP Requirements UDR Base Case



Major parameter and modeling enhancements that influenced the 2006-07 NYCA IRM requirement study results include:

- ***Interconnection Support during Emergencies.*** NYCA reliability can be improved by receiving emergency assistance support from other interconnected Control Areas — in accordance with control area reserve sharing agreements during emergency conditions. Assuming such arrangements in the Base Case permits the NYCA IRM to be approximately 6 percentage points lower than is otherwise required (see Table 1). The Year 2006 Study applied a new model for representing the neighboring Control Areas. Previous IRM studies represented each of these Areas with just a single area. Instead, this study represents two of the Outside World Areas, ISO-NE and PJM, with multi-area models. This level of granularity better captures the impacts of transmission constraints within these Areas, particularly on their ability to provide emergency assistance to the NYCA.

  This study also included several enhancements to the modeling of transmission interface limits. Limitations across the Northport-Norwalk Harbor cable were modeled as a function of the availability of Norwalk Harbor generation. Limitations across the Con Edison Hudson-Farragut and Linden-Gothels lines were modeled as a function of the availability of Northern New Jersey generation including Linden, Hudson, and Bergen.

- ***Peak Load Forecast.*** The Base Case peak load forecast has a direct impact on IRM Requirements with respect to the relationship between Upstate NY and Downstate NY loads. The load forecast used for the Year 2005 Study projected a 51.1% share of the NYCA load for Downstate NY; the Year 2006 Study reflects an increased Downstate NY share of load at 51.9%. The larger load share for Downstate NY has an impact on the Year 2006 IRM Requirement (see NYCA "Transmission Constraints".)

- ***Resource Capacity Availability.*** Generating unit forced and partial outages are modeled in GE-MARS by inputting a multi-state outage model that represents an "equivalent forced outage rate on demand" (EFORd) for each unit represented. Outage data is received by the NYISO from generator owners based on specific reporting requirements established by the NYISO. Capacity unavailability is modeled by considering forced and partial outages that occur over the most recent 5-year time period.

  Although generating unit availability has improved in recent years, this recorded improvement has been somewhat offset by overstating the availability of certain resources reported to the NYISO. This situation was revealed in the reviews of actual outage data conducted by the NYISO's Market Monitoring & Performance group. Two primary reasons for this overstatement are: (1) In past years, generator owners have not been required to report partial and forced outages that were attributed to transmission failures, fuel shortages, or environmental limitations; (2) NYISO audits discovered that in certain cases, Generating Availability Data System (GADs) data supplied by generation owners have overstated unit availability.

The NYISO has since taken steps to mitigate past capacity availability overstatements by improving generating unit availability reporting requirements. These initiatives have included modification of outage data collection software, requirements for the reporting of generation unavailability caused by transmission outages, education efforts, and expanding the number of audits. To account for this resource availability overstatement, the Year 2005 Study incorporated a reduction in statewide DMNC capacity of 711 MW. However, because of improved outage reporting, the Year 2006 Study reduced this DMNC adjustment to 125 MW.

Incorporation of generating unit outage rates from the most recent 5-year time period and the reduced DMNC adjustment described above resulted in an IRM requirement decrease of approximately 4.0 percentage points from last year's study (see Table 2).

- ***NYCA Transmission Constraints.*** GE-MARS is capable of determining the impact of transmission constraints on the NYCA LOLE. This study, as with previous GE-MARS studies, consistently reveals that the transmission system into NYC and LI is constrained and can impede the delivery of emergency capacity assistance required to meet load within these zones. The NYSRC has two reliability planning criteria that recognize transmission constraints: 1) the NYCA IRM requirement considers transmission constraints into NYC and LI (see Reliability Criterion section), and 2) minimum LCRs must be maintained for both NYC and LI.

  The impact of transmission constraints on NYCA IRM requirements depends on the level of resource capacity in NYC and LI. In accordance with NYSRC Reliability Rule A-R2, *Load Serving Entity ICAP Requirements,* the NYISO is required to calculate and establish appropriate LCR. The most recent NYISO study (*Locational Installed Capacity Requirements Study,* dated February 17, 2005) determined that for 2005 the LCR for NYC and LI were 80**%** and 99**%**, respectively.

  As previously discussed, Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI for the UDR Base Case. (The IRM requirements and LCRs in the discussion below are derived from study results assuming UDRs as considered in the UDR Base Case.) This figure shows that the IRM requirement can be impacted significantly depending on the level of capacity within these zones, particularly to the right of the "knee" or "anchor point" of the curve where the IRM requirement rises much faster than the locational installed capacity level can be reduced. For UDR Base Case assumptions, the anchor point in Figure 2 results in the Base Case IRM Requirement of 18.0**%** and NYC and LI MLCR levels of 82.5**%** and 106.0**%**, respectively.

  Results from this study illustrate IRM requirement impacts for changes of locational installed capacity level assumptions from the UDR Base Case. Observations from these results include:

    - **Unconstrained NYCA Case** - If internal transmission constraints were entirely eliminated the NYCA IRM requirement could be reduced to 15.7%, 2.3 percentage points less than the UDR Base Case IRM Requirement. (See Table 1.)

- o **Downstate NY Capacity Levels** - If the NYC and LI locational installed capacity levels were *increased* from the UDR Base Case results to 83.5% and 107.0%, respectively, the IRM requirement would be reduced by 0.5 percentage points to about 17.5%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 81.5% and 105.0%, respectively, the IRM Requirement would increase by one percentage point to about 19.0%. (See Figure 2.)

- o **2005 LCR Levels** - If the NYC and LI locational installed capacity levels were *decreased* from the UDR Base Case results to their 2005 LCR values of 80% and 99%, respectively, would increase the IRM requirement to over 21%. (See Figure 2.) This year's Base Case load forecast for Downstate NY increased relative to the Upstate NY forecast, which exacerbated the impact of transmission constraints on IRM Requirements (refer to "Peak Load Forecast" discussion above for more detail).

These results illustrate the significant impact on IRM when changing locational installed capacity levels, assuming all other factors being equal. In 2005 the NYSRC and NYISO recognized this relationship and the potential impact on reliability and thereby jointly developed the anchoring method used in this study. The MLCR parameter ensures that the NYCA IRM Requirement will meet NYSRC Reliability Rule A-R1.

Other important factors that impact IRM studies include:

- ***Load Forecast Uncertainty (LFU).*** It is recognized that some uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty is incorporated in the model by using a load forecast probability distribution that is sensitive to different weather and economic conditions. Recognizing the unique LFU of individual NYCA areas, the LFU model is subdivided into three areas: NYC, LI, and the rest of New York State.

- ***Special Case Resources (SCRs)***. SCRs are ICAP resources that include loads that are capable of being interrupted — and distributed generation that may be activated on demand. This study assumes 1016 MW of SCR capacity resource capacity in July and August (and lesser amounts during other months).

- ***Emergency Demand Response Programs (EDRP).*** EDRP allows registered interruptible loads and standby generators to participate on a voluntary basis - and be paid for their ability to restore operating reserves. This study assumes 210 MW of EDRP capacity resources in July and August (and less in other months). The study also assumed a maximum of five monthly EDRP calls. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model.

- ***Other Emergency Operating Procedures.*** The NYISO will implement EOPs as required to minimize customer disconnections. If an 18.0% IRM is maintained, firm load disconnections due to inadequate resources will not occur more than once in every ten years on average — in accordance with NYSRC and NPCC criteria. (Refer to Appendix B, Table B-2, for the expected use during 2006 of SCRs, EDRP, voltage reductions, and other EOPs.)

SENSITIVITY CASE STUDY RESULTS

Determining the appropriate IRM Requirement to meet NYSRC reliability criteria depends upon many factors. Variations from the base case will, of course, yield different results. Table 1 shows IRM requirement results and related NYC and LI locational capacities for several sensitivity cases that **do not** include the UDR model represented in the UDR Base Case. (Sensitivity case results are also listed in Appendix B, Table B-1.)

Due primarily to time and resource constraints, there was no attempt to re-evaluate the "anchor point" for each sensitivity (see Study Procedure section). Therefore, each sensitivity case reflects the initial Base Case (and LCRs) built around the Non-UDR Case, as shown in Table 1. From results seen thus far, it is expected that sensitivities run using the UDR Base Case would be somewhat higher than is shown in Table 1.

Table 1
Sensitivity Case Results – Non-UDR Case
NYCA IRM Requirements and Related NYC & LI Locational Capacities

Case	Case Description	IRM (%)	% Change from Non-UDR Case	NYC (%)	LI (%)
	Non-UDR Case	**17.5**	**--**	**82**	**99.5**
1	NYCA Isolated	23.2	+5.7	86	104
2	No SCRs & EDRP	22.7	+5.2	86	104
3	No Voltage Reductions	19.6	+2.1	83.5	101
4	No NYS Transmission System Constraints	15.5*	-2.0*	**	**
5	External Control Area IRMs: -10%	18.6	+1.1	84	100.5
6	External Control Area IRMs: +10%	11.1	-6.4	77.5	95
7	GADf Derate: 0 MW	17.2	-.3	82	99
8	GADf Derate: 250 MW	17.8	+.3	82	100

* With UDRs modeled for the Sound Cable Crossing, the IRM requirement is 15.7%, 2.3% less than UDR Base Case IRM requirements.
** Locational capacities are not relevant for this case.

NYISO IMPLEMENTATION OF THE NYCA IRM REQUIREMENT

NYISO Translation of NYCA Capacity Requirements to Unforced Capacity:

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units — Unforced Capacity or "UCAP". To maintain consistency between the rating of a unit (UCAP) and the statewide ICR, the ICR must also be translated to an unforced capacity basis. In the NYCA, these translations occur twice during the course of each capability year, prior to the start of the summer and winter Capability Periods.

Additionally, any LCR in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another, and is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts UCAP requirements to ICAP in a manner that assures compliance with NYSRC Resource Adequacy Rule A-R1. The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

NYISO Implementation of a Spot Market Auction based on a Demand Curves:

Effective June 1, 2003 the NYISO replaced its monthly Capacity Deficiency Auction with a monthly Spot Market Auction based on three FERC-approved Demand Curves. Demand Curves are developed for zones J, K, and the rest of NYCA.

The existence of Demand Curves does not impact the determination of IRM requirements by the NYSRC.

COMPARISON WITH 2005 IRM STUDY RESULTS

The results of the Year 2006 IRM study show that the IRM requirement has decreased 0.1 percentage points for the Non-UDR Case and increased by 0.4 percentage points for the UDR Base Case, compared to the Year 2005 IRM Study. Table 2 below compares the approximate IRM impacts of changing certain several key study assumptions from the 2005 Study. The primary drivers that changed the IRM Requirement from 2005 include updated generating unit availability, peak load forecast, and load forecast uncertainty representations.

It is interesting to note that if the previous study methodology used for the 2005 Study was also used for this 2006 Study -- along with the 2006 Base Case assumptions and the 2005 LCR of 80% and 99% for NYC and LI, respectively -- the NYCA 2006-07 IRM requirements – the IRM requirement would have determined to be over 19%. This is because the new Unified and IRM Anchoring Methods anchored the LCR at higher than the 2005 capacity levels, which resulted in the 2006 Study's lower Base Case IRM requirements.

Table 2
Parametric IRM Impact Comparison with 2005 Study*

Parameter	Approximate IRM Req. Change (%)	IRM Req. (%)
Previous 2005 Study – Base Case IRM Result		**17.6**
Updated Peak Load Forecast	+1.3	
Updated EFORs and Reduced DMNC Adjustment, from 711 to 125 MW	-4.0	
Updated LFU Representation	+1.9	
New Generating Units & Retirements	-0.8	
Updated SCR and EDRP Capacity & Other EOPs	-0.4	
Updated NYS Transmission System Limits	+0.9	
New Outside World Multi-Area Representation	+1.0	
Net Change from 2005 Study	-0.1	
2006 Study – Non-UDR Case IRM Result		**17.5**
With CSC UDRs Represented	+.5	
Net Change from 2005 Study	+.4	
2006 Study – UDR Base Case IRM Result		**18.0**

*This table reconciles assumption changes between the 2005 and 2006 studies.

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APPENDIX A

NYCA INSTALLED CAPACITY REQUIREMENT RELIABILITY CALCULATION MODELS AND ASSUMPTIONS

Description of the GE-MARS Program;
Load, Capacity, Transmission and Outside World Models;
And Assumptions.

A-1 Introduction

Appendix A provides details of the modeling and assumptions for the NYCA IRM study covered in this report.

The reliability calculation process for determining the NYCA IRM requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation for "Loss of Load Expectation" (LOLE) provides a consistent measure of system reliability. The various models used in the NYCA IRM calculation process are depicted in Figure A-1.

Table A-1 lists the study parameters in the Figure A-1 models, the source for the study assumptions, and where in Appendix A the assumptions are described. Finally, the last page of Appendix A compares the assumptions used in the 2005 and 2006 IRM reports.

Table A-1
Details on Study Parameters

Internal NYCA Modeling:

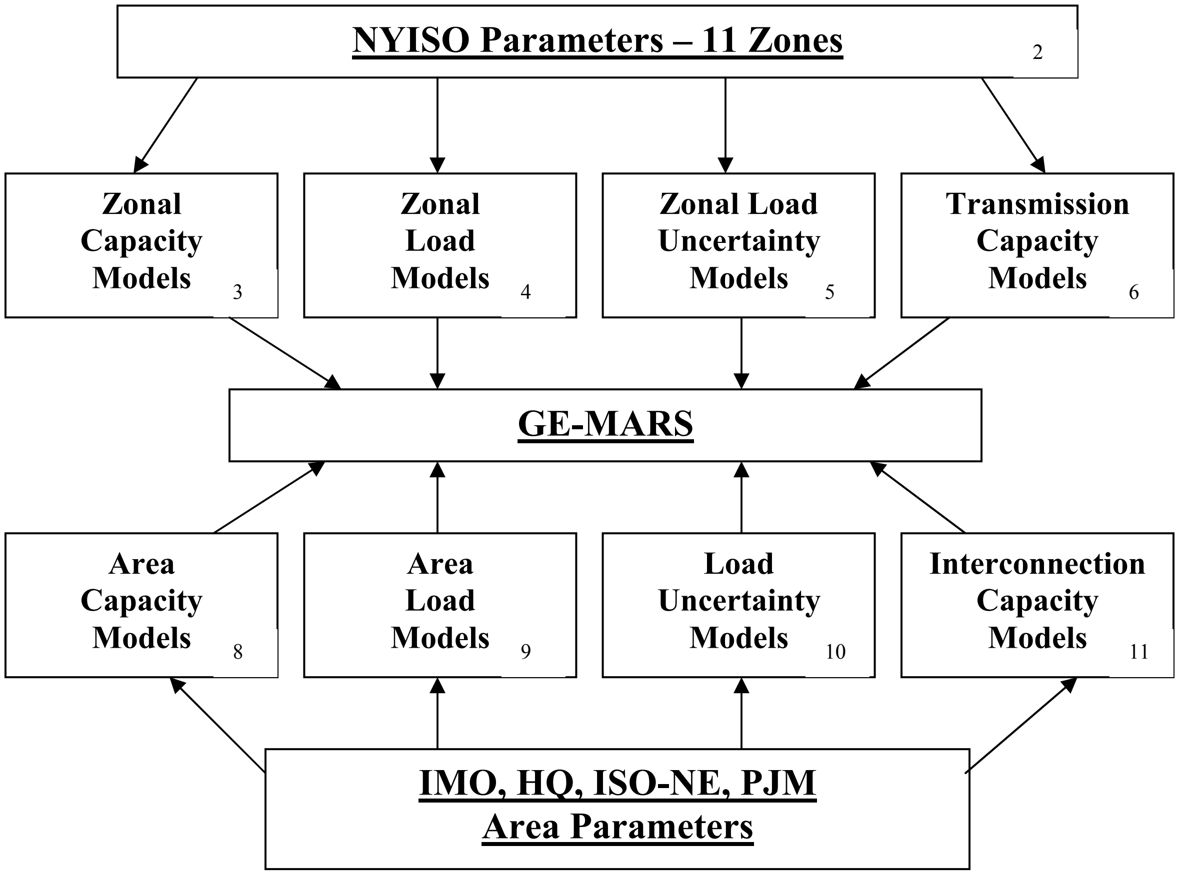
Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	GE-MARS	The General Electric Multi-Area Reliability Simulation Program		See page 20
2	11 Zones	Load areas	Fig. A-2 page 23	NYISO Accounting & Billing Manual
3	Zone Capacity Models Emergency Operating Procedures	-Generator Models for each generating unit in Zone. -Generating Availability. -Unit Ratings. Reduces load during emergency conditions to maintain operating reserves.	 GADS Data 2005 Gold Book* NYISO	See page 28 See page 28 See page 36
4	Zone Load Models	Hourly loads	NYCA load shapes. NYISO peak forecasts.	See page 25 32,400 MW Gold Book
5	Load Uncertainty Model	Account for forecast uncertainty due to weather and economic conditions.	Historic Data	See page 27
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones.	NYISO transmission studies	See page 38

External Control Area Modeling:

7	IMO, HQ, ISO-NE, PJM control area Parameters	See the following items 8-11.		
8	External Control Area Capacity Models	Generator Models in neighboring control areas	NPCC CP-8 study for IMO and HQ. Area data from PJM & NE	See page 45
9	External Control Area Load Models	Hourly Loads	Same as above	See page 45
10	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather and economic conditions	NPCC CP-8 Study	See page 45
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	NPCC CP-8 Study	See page 44

* "2005 Load & Capacity Data" Report issued by the NYISO.

Figure A-1
NYCA ICAP Modeling



A-2 Computer Program Used for Reliability Calculation

As the primary probabilistic analysis tool used for establishing NYCA IRM requirements, the GE-MARS program includes a detailed load, generation, and transmission representation for 11 NYCA Zones, as well as the four external Control Areas (Outside World Areas) interconnected to the NYCA (see Sections A-3 and A-5.6 for a description of these Zones and Outside World Areas).

A sequential Monte Carlo simulation forms the basis for GE-MARS. The Monte Carlo method provides a fast, versatile and easily expandable program that can be used to fully model many different types of generation, transmission and demand-side options.

GE-MARS calculates the standard reliability indices of daily and hourly LOLE (days/year and hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A-5.3).

In addition to calculating the expected values for the reliability indices, GE-MARS also produces probability distributions that show the actual yearly variations in reliability that the NYCA could be expected to experience. In determining NYCA reliability, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units and transmission capacity. Monte Carlo simulation models the effects of such random events. Deviations from the forecasted loads are captured by the use of a load forecast uncertainty model.

Monte Carlo simulation approaches can be categorized as “non-sequential” and “sequential”. A non-sequential simulation process does not move through time chronologically or sequentially, but rather considers each hour to be independent of every other hour. Because of this, non-sequential simulation cannot accurately model issues that involve time correlations, such as maintenance outages, and cannot be used to calculate time-related indices such as frequency and duration.

Sequential Monte Carlo simulation (used by GE-MARS) steps through the year chronologically, recognizing the status of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment’s mean time to repair. Sequential simulation can model issues of concern that involve time correlations, and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

Because the GE-MARS Program is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if one assumes that the unit’s capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit’s capacity state in any given hour is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} = \frac{\text{(Number of Transitions from A to B)}}{\text{(Total Time in State A)}}$$

The table below shows the calculation of the state transition rates from historic data for one year. The Time-in-State Data shows the amount of time that the unit spent in each of the available capacity states during the year; the unit was on planned outage for the remaining 760 hours. The Transition Data shows the number of times that the unit transitioned from each state to each other state during the year. The State Transition Rates can be calculated from this data. For example, the transition rate from state 1 to state 2 equals the number of transitions from 1 to 2 divided by the total time spent in state 1:

TR (1 to 2) = (10 transitions) / (5000 hours) = 0.002

Example of State Transition Rates

Time-in-State Data		
State	**MW**	**Hours**
1	200	5000
2	100	2000
3	0	1000

Transition Data			
From State	**To State** 1	**2**	**3**
1	0	10	5
2	6	0	12
3	9	8	0

State Transition Rates			
From State	**To State** 1	**2**	**3**
1	0.000	0.002	0.001
2	0.003	0.000	0.006
3	0.009	0.008	0.000

From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state to each other state.

Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when the next random state change will occur. The second random number is combined with the state transition probabilities to determine the state to which the unit will transition when it leaves its current state. The program thus knows for every unit on the system, its current state, when it will be leaving that state, and the state to which it will go next.

Each time a unit changes state, as a result of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

A-2.1 Error Analysis

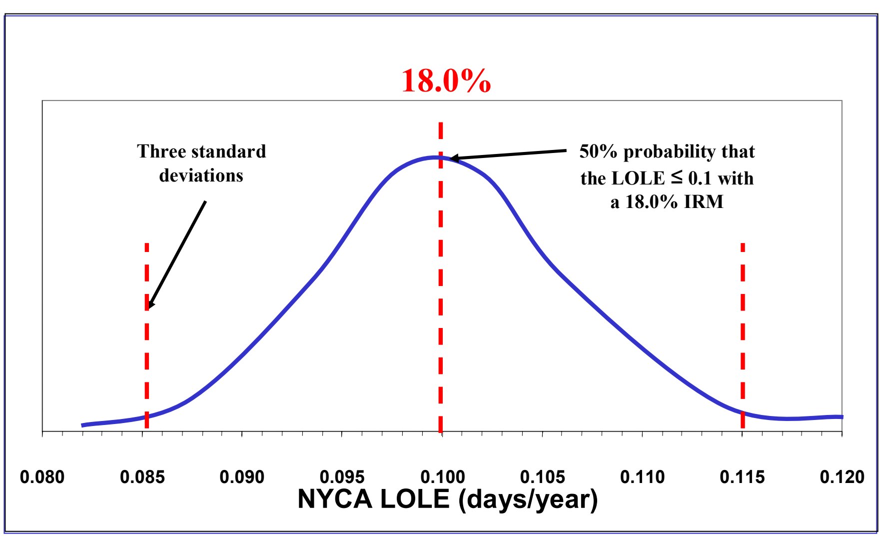
An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical convergence is measured by the standard deviation of the estimate of the reliability index that is calculated from the simulation data.

The standard deviation has the same physical units (e.g., days/year) as the index being estimated, and thus its magnitude is a function of the type of index being estimated. Because the standard deviation can assume a wide range of values, the degree of convergence is often measured by the standard error, which is the standard deviation of the estimated mean expressed as a per unit of the mean.

Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls based on the simulation data. For example, a range centered on the mean of three standard deviations in each direction (plus and minus) defines a confidence interval of 99.7%.

For this analysis, the Base Case required 1148 replications to converge to a daily LOLE for NYCA of 0.1 days/year with a standard error of 0.05 per unit, which corresponded to an IRM of 18.0 %. For a 99.7% confidence interval (plus and minus three standard deviations about the mean), the IRMs that would result in a NYCA LOLE of 0.085 days/year and 0.115 days/year were computed. The resulting IRM values of 17.6% and 18.5% define the 99.7% confidence interval. The statistical significance of the 17.6%, 18.0% and 18.5% numbers are a 0.15%, 50% and 99.85% probability of meeting the one in ten criterion, assuming perfect accuracy in all parameters.

Confidence Intervals



A-3 Representation of the NYCA Zones

Figure A-2 depicts the NYCA Zones represented in GE-MARS.

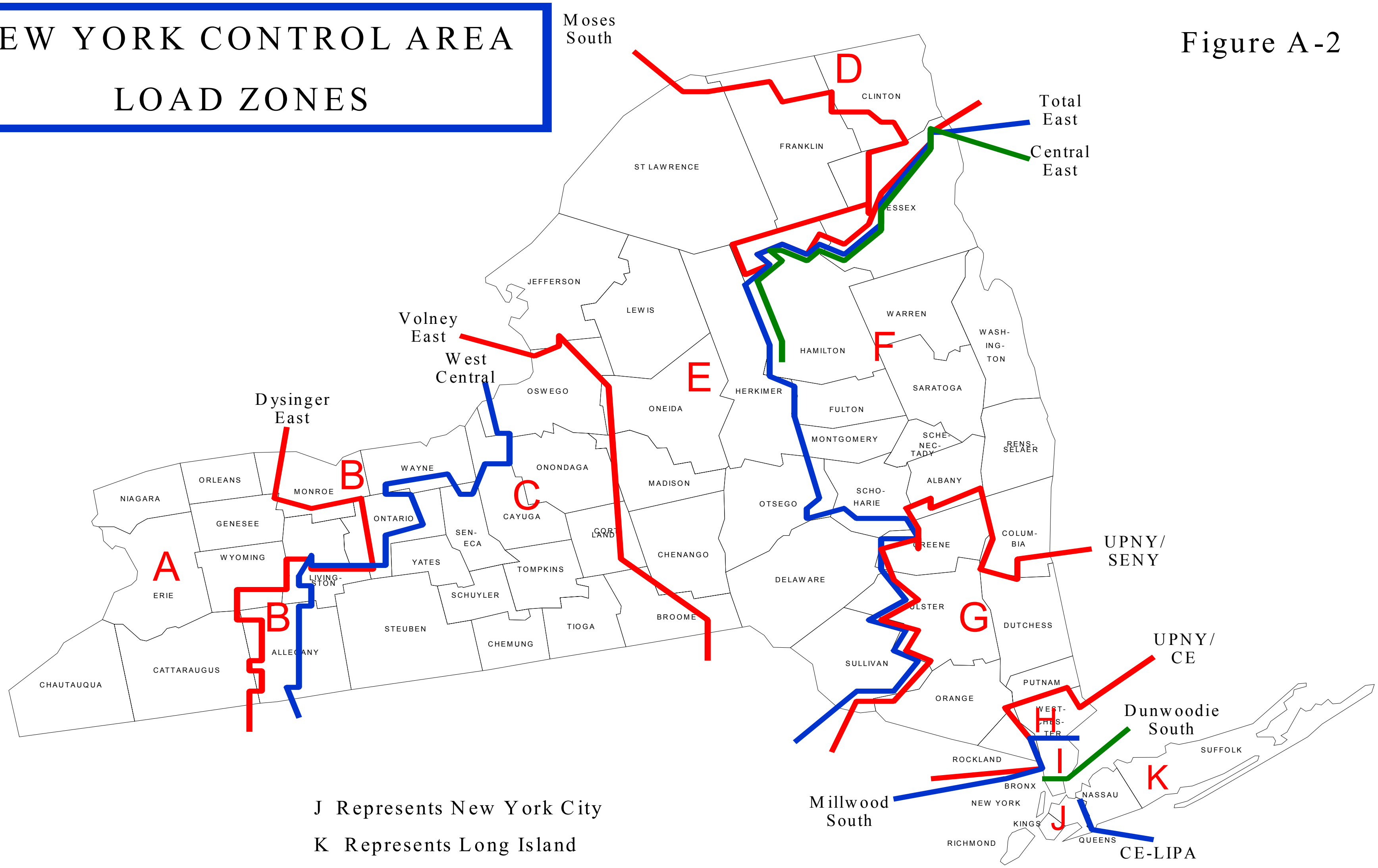
A-4 Conduct of the GE-MARS Analysis

An updated GE-MARS software version (executable version 2.69) was tested to ensure that the new version produced acceptable results. The test compares results derived using the current GE-MARS version 269 with results based on a previous GE-MARS version 2.59 using the same assumptions.

The current base is the culmination of the individual changes made to last year's base case. Each change, however, is evaluated individually against last year's Base Case. The LOLE results of each of these pre-base case simulations are reviewed to confirm that the reliability impact of the change is reasonable and explainable.

NEW YORK CONTROL AREA LOAD ZONES

Figure A-2



The top three summer peak loads of all Areas external to NYCA are aligned to be on the same days as that of NYCA, even though they may have historically occurred at different times. This is a conservative approach, using the assumption that peak conditions could be the result of a wide spread heat wave. This would result in minimizing the amount of assistance that NYCA could receive from the other Areas.

A-4.1 New Methodology

This year a new methodology called the Unified Methodology was developed to simultaneously determine the NYCA installed reserve requirements and locational requirements.

In the past, the NYCA IRM has been calculated by starting with the current load forecast and generating capacity. Since NYCA has had excess capacity, the IRM to achieve a one day in ten LOLE was determined by adding load to each of the zones in proportion to the Zone's peak load. If the locational capacity to peak load ratios for zones J and K at criteria were below the previous year's locational capacity requirements, they were adjusted to meet the locational requirements.

STEP 1. The unified methodology starts with the forecasted loads for each zone and NYCA, capacity is then removed from the zones west of the Central East interface that have capacity in excess of their peak loads until the targeted NYCA IRM is reached. The capacity is removed proportionally to the amount of excess capacity in each of the zones. (Various IRM values are chosen so a curve can be drawn.) This capacity is removed by adding negative perfect capacities to these zones. For calculation purposes, this perfect capacity is translated to real capacity using the average availability of the existing capacity in that zone.

STEP 2. Remove capacity from Zone J (in the same manner as above) and add an equivalent capacity spread among the identified zones above until 0.1 LOLE is reached. This perfect capacity is translated to real capacity using the availability of a new combined cycle unit.

STEP 3. Starting with the system in step 1, capacity is removed from Zone K in a similar manner.

STEP 4. Again starting with the system in step 1, capacity is removed simultaneously from Zones J and K in proportion to the capacity removed in steps 2 and 3 and an equivalent amount of capacity is added to the identified zones above until 0.1 LOLE is achieved.

STEP 5. This process is repeated with different IRM values so a curve can be drawn.

For each point on the curve, the minimum loacational requirements for Zones J and K are identified.

This year a test case was run using the new input data and the old methodology to check for any obvious errors. None were found.

A final step is to check that none of the surrounding Areas are more reliable then NYCA on an isolated basis. If they are, then their loads are increased until this is no longer the case. This is done so that NYCA is not overly dependent on its neighboring systems.
From this, the NYCA generating capacity modeled minus net sales is divided by the peak NYCA load to determine the IRM.

In addition to crating the curve a number of sensitivity studies are run at the anchor point to show the IRM requirement outcomes for different assumptions.

A-5 Input Data and Models

A-5.1 NYCA LOAD MODEL

The 2006 IRM study (last year's study) was performed using a load shape based on 2002 actual values.

For the 2006 IRM study, Load Forecasting staff re-evaluated the 2003 hourly load shape. The purpose was to determine if the 2003 experience offered any new information that would cause a re-evaluation of whether or not to use the 2002 load shape. As was the case for the 2005 study, the NYSRC ICS concluded that the 2003 shape was not preferable to the 2002 shape

Load Forecasting staff also concluded that the 2004 load shape was unrepresentative. The 2004 peak occurred on June 9, the earliest ever NYCA peak. In addition, the entire summer was very cool and no conditions that are associated with peak or near-peak loads were ever encountered.

The balance of load in New York continues to migrate downstate. Zone J's share, based on the most recent information, appears to have achieved a peak in 2001. Since then, it has been declining. However, Zone K has more than made up the difference, resulting in continuing decline in the share for the rest of the State (i.e., A – I).

Share of NYCA Peak Load Accounted for by Load In:

	J	K	A - I
1995	32.2%	13.4%	54.4%
1996	32.2%	13.4%	54.4%
1997	32.8%	13.9%	53.3%
1998	33.1%	14.4%	52.5%
1999	34.0%	15.3%	50.7%
2000	34.4%	15.3%	50.2%
2001	34.5%	15.4%	50.1%
2002	34.2%	15.7%	50.1%
2003	34.0%	15.8%	50.2%
2004	34.0%	16.0%	50.0%
2005	33.9%	16.1%	50.0%

(Average of current and preceding two years.)

Weather Analysis

2004 had an unusually cool summer. Conditions associated with peak or near-peak loads were not experienced. As can be seen, the 2004 Combined Temperature Humidity Index (CTHI) for 2004 lies well below the median curve for the highest seventy days. This accounts for the unsuitability of 2004's load shape as a model for the 2006 IRM Study.

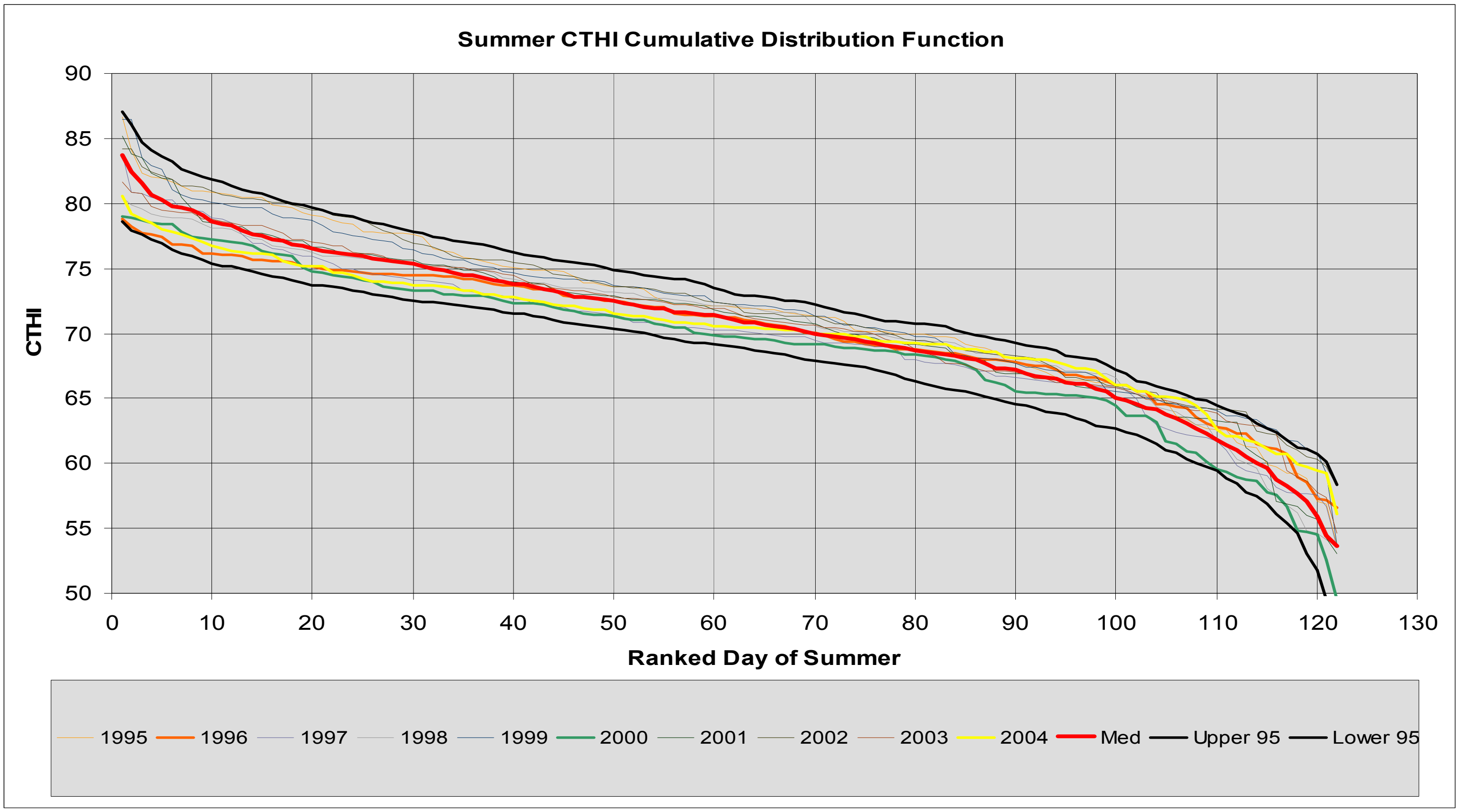


Figure A-3

A-5.1.1 ZONAL LOAD FORECAST UNCERTAINITY

For 2006, new load forecast uncertainty models were provided by Consolidated Edison and LIPA for Zones J and K respectively. A new model was developed for A – I (i.e., NYCA Net).

The models are presented below.

2006 Load Forecast Uncertainty Models

Multiplier	NYCA Tot	Con Ed (J)	LIPA (K)	NYCA Net
0.0062	1.0584	0.8972	1.1552	1.1300
0.0606	1.0499	0.9066	1.0970	1.0900
0.2417	1.0250	0.9319	1.0485	1.0400
0.3830	1.0000	0.9642	1.0000	1.0000
0.2417	0.9770	1.0000	0.9515	0.9600
0.0606	0.9460	1.0325	0.9030	0.9100
0.0062	0.9070	1.0481	0.8448	0.8700

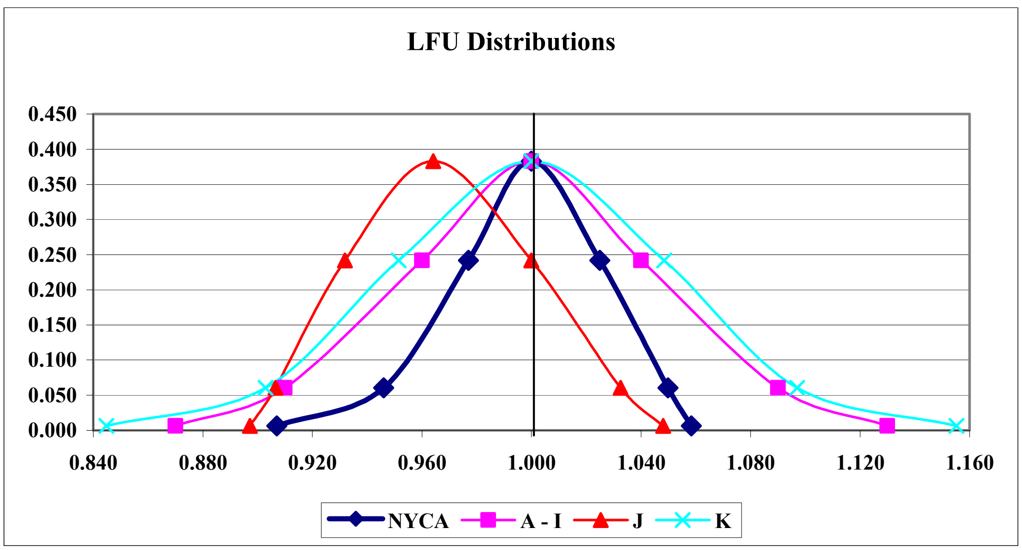


Figure A-4
Load Forecast Uncertainty Distributions

The Con Ed (J) model now reflects the fact that the load forecast used for Zone J has a 1:3 instead of 1:2 chance of occurrence.

The LIPA model is only marginally different than that used in 2005.

A new NYCA Net model was developed as when much higher than expected weather responsiveness was observed for load in this area early in the 2005 summer capability period. The new model was developed by simulating several historical high CTHI observations in the NYCA day-ahead forecast model. The predicted peak loads were then used to estimate a new uncertainty distribution.

A-5.2 NYCA Capacity Model

The capacity model input to GE-MARS incorporates the several types of resource capacity used to serve load in the NYCA. The following were changes made to the existing capacity shown in table III-2 of the "2005 Load and Capacity Data" (Gold Book):

- **Retirements:**

Waterside 6, 8 & 9	167 MW	Zone J

- **New Units: (Units installed during 2005)**

East River Repowering	288 MW	Zone J
Bethlehem	750 MW	Zone F

- **Planned Units for 2006:** (These units had a signed interconnection agreement by August 1, 2005.)

Poletti Expansion (1/06)	500MW	Zone J
Flat Rock (12/05)	198MW	Zone E
SCS Astoria (4/06)	500 MW	Zone J
Calpine Bethpage CC (9/05)	79.9MW	Zone K
Pinelawn steam (9/05)	79.9 MW addition	Zone K
Cedars[5]	200MW	Zone D

This section describes how each resource type is modeled in GE-MARS.

Generating Units

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State. This model requires the following input data:

Unit Ratings. The rating for each generating unit is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. The 2005 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

Unit Performance. Performance data for all generating units in the model includes forced and partial outages, which are modeled by inputting a multi-state outage model that is representative of the "equivalent demand forced outage rate" (EFORd) for each unit represented. Generation owners provide outage data to the NYISO using Generating Availability Data System (GADS) data in accordance with the NYISO Installed Capacity Manual. The NYSRC is continuing to use a five-year historical period for the 2006 IRM Study. (See Figure A-5)

The multi-state model for each unit is derived from five years of historic events if it is available. For units with less then five years of historic events, the available years of event data collected since the inception of the NYISO is used if it appears to be reasonable. For the remaining units NERC class-average data is used.

5 This unit is modeled as a NYCA resource in the IRM study.

The unit forced outage states for the majority of the large steam units were obtained from the five-year average NERC - GADS outage data collected by NYPP and the NYISO for the years 2000 through 2004. This hourly data represents the availability of the units for all hours. From this, full and partial outage states and the frequency of occurrence were calculated and put in the required format for input to the GE-MARS program

A recent NYISO Market Monitoring review of actual outage data revealed that, although generating unit availability has shown improvement in recent years, this recorded improvement has been somewhat mitigated by the overstatement of the availability of certain resources reported to the NYISO. There are two primary reasons for this overstatement: (1) In the past generator owners have not been required to report partial and forced outages that were attributed to transmission failures, fuel shortages, or environmental limitations; (2) Recent NYISO audits discovered that in certain cases, GADS data supplied by generation owners have overstated unit availability. The NYISO has since taken steps to improve future generating unit availability reporting requirements. To account for this resource availability overstatement, this study incorporates a reduction in statewide DMNC capacity of 125 MW. This is documented in the "Report Adjusting for the Current Overstatement of Resource Availability in Resource Adequacy Studies", dated August, 2005.

A second performance parameter to be modeled for each unit is scheduled maintenance. This parameter includes both planned and maintenance outage components. The planned outage component is obtained from the generator owners, and where necessary, extended so that the scheduled maintenance period equals the historic average using the same period used to determine EFORd averages.

Flat Rock, a wind generator is modeled as an hourly load modifier. The output of the unit varies between 0 and 198 MW based on wind data collected near the Flat Rock site during 2002. The 2002 hourly wind data corresponds to the 2002 hourly load shape also used in the model. Characteristics of this data indicate an overall 30 % capacity factor with a capacity factor of 11% during the summer peak hours.

Figure A-5

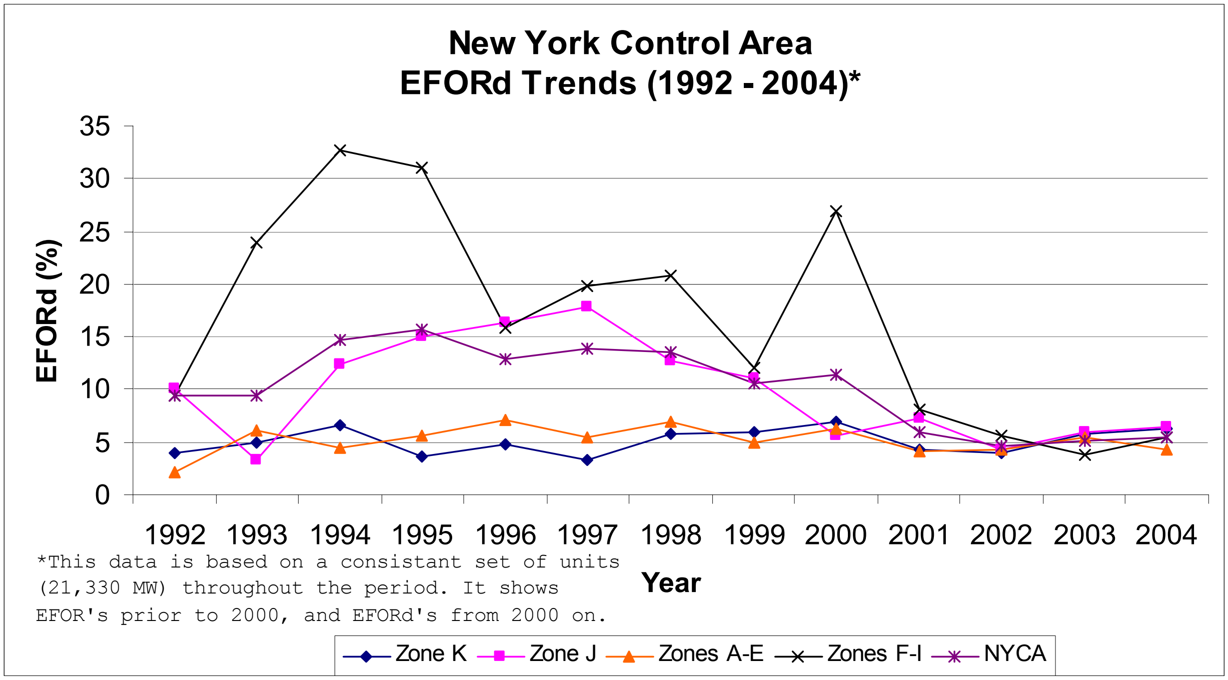


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd). The graph presents unit weighted averages for four areas within the NYCA along with a NYCA total aggregate

Equivalent Availability. The equivalent availability factor accounts for forced, partial, scheduled and maintenance outages. Figure A-6, which is based on NERC-GADS data for New York units, shows that there is a continued trend of improved reliability.

Figure A-7 provides NERC-GADS data industry-wide. The continued improved availability is similar to that experienced in the NYCA. Note that the year 2004 data from NERC is not available at this date.

Figure A-6

NYCA EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 – 2004

ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL & GAS, AND COMBUSTION TURBINES

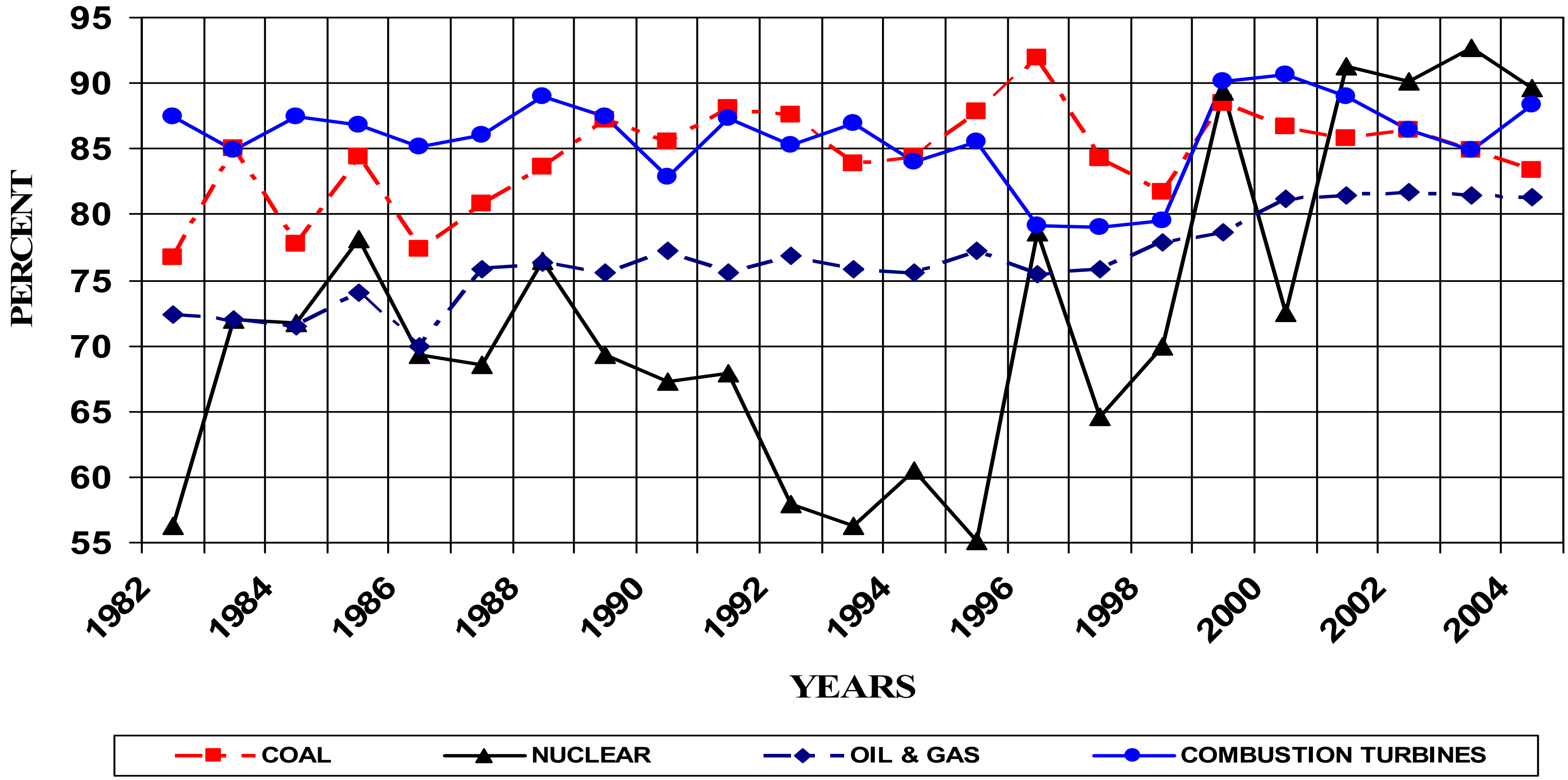
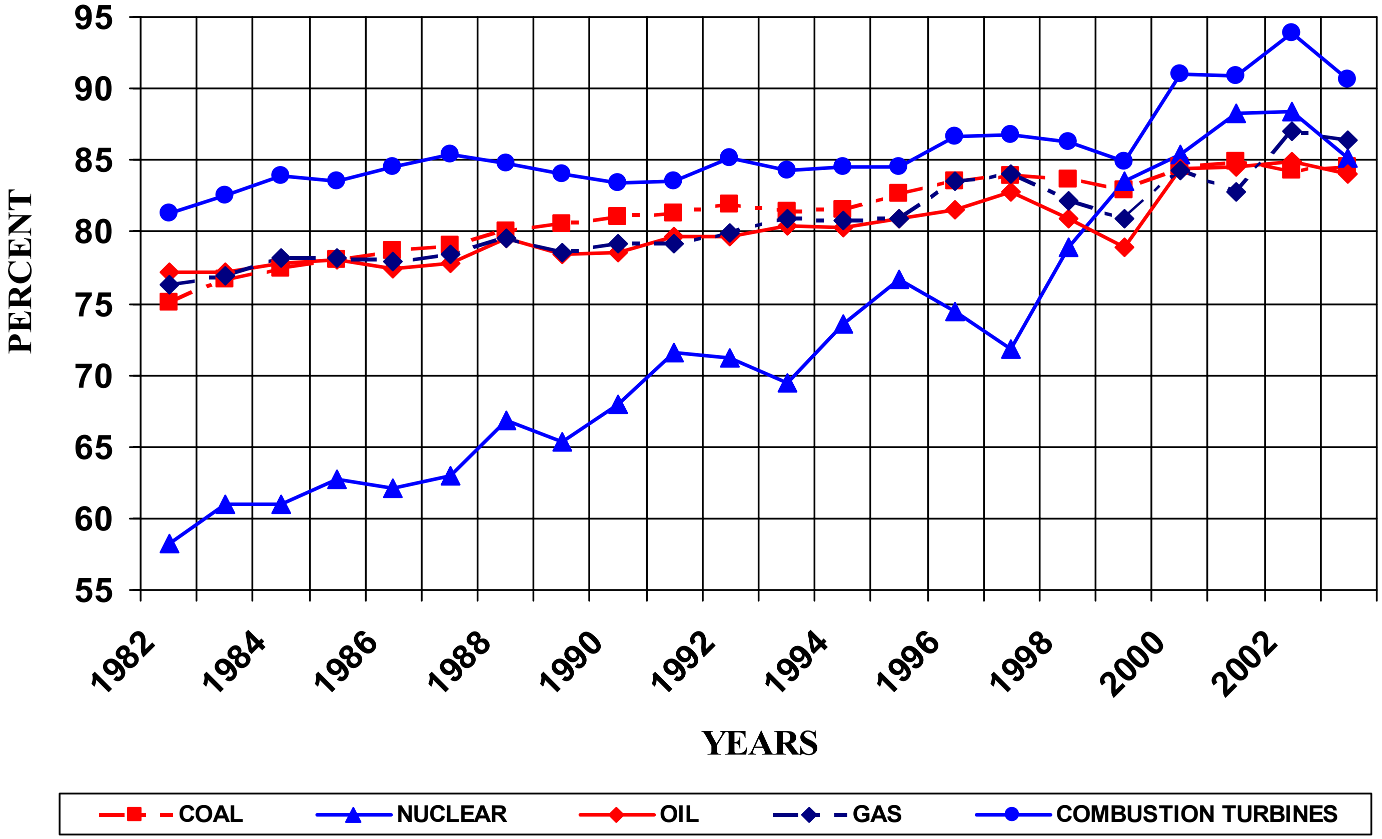


Figure A-7

NERC EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 - 2003

ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL, GAS, AND COMBUSTION TURBINES



Scheduled Maintenance. The total amount of scheduled maintenance, including both planned and maintenance outages, was developed from a five-year average of the same NERC-GADS data used to obtain the forced outage rates.

The forecast of the planned outages for the study period were obtained from the generation owners, and where necessary, the length of the outage was extended so that it equaled the five-year historic outage time period. Figure A-8 provides a graph of scheduled outage trends over the 1992 through 2004 period for NYCA generators.

Figure A-8

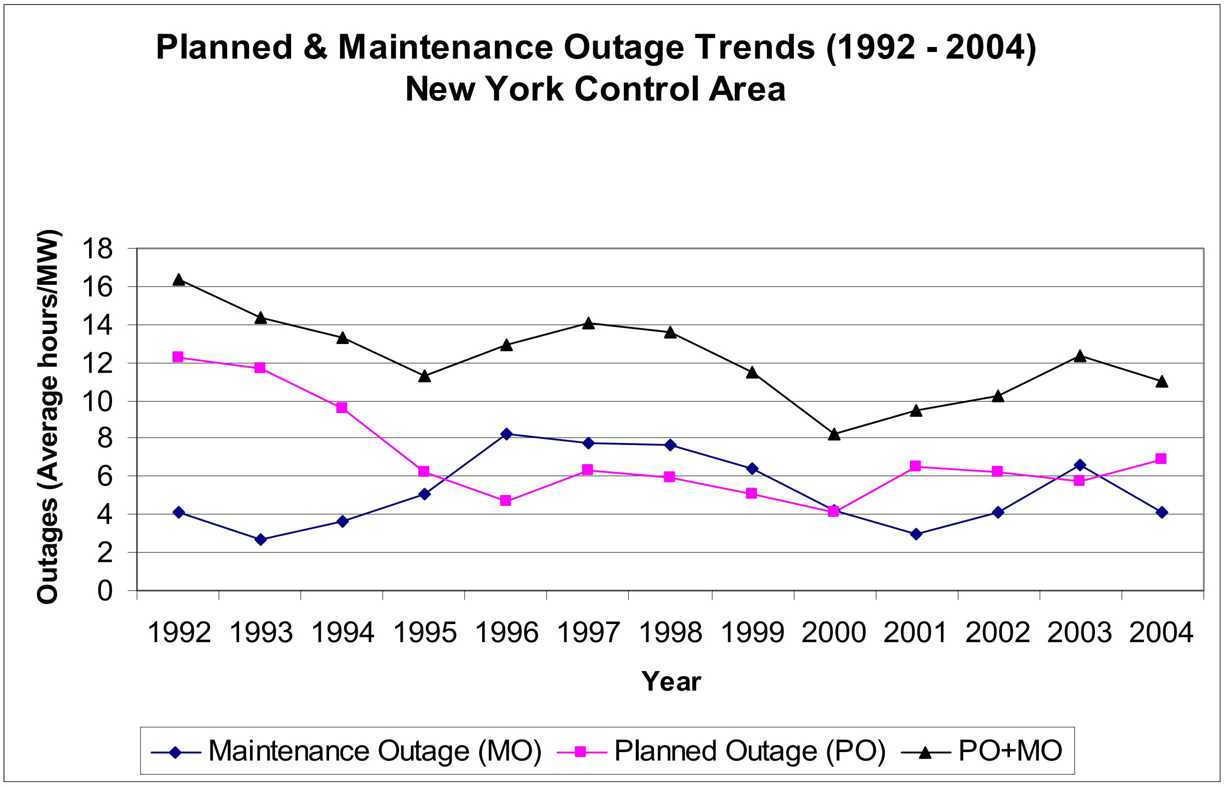
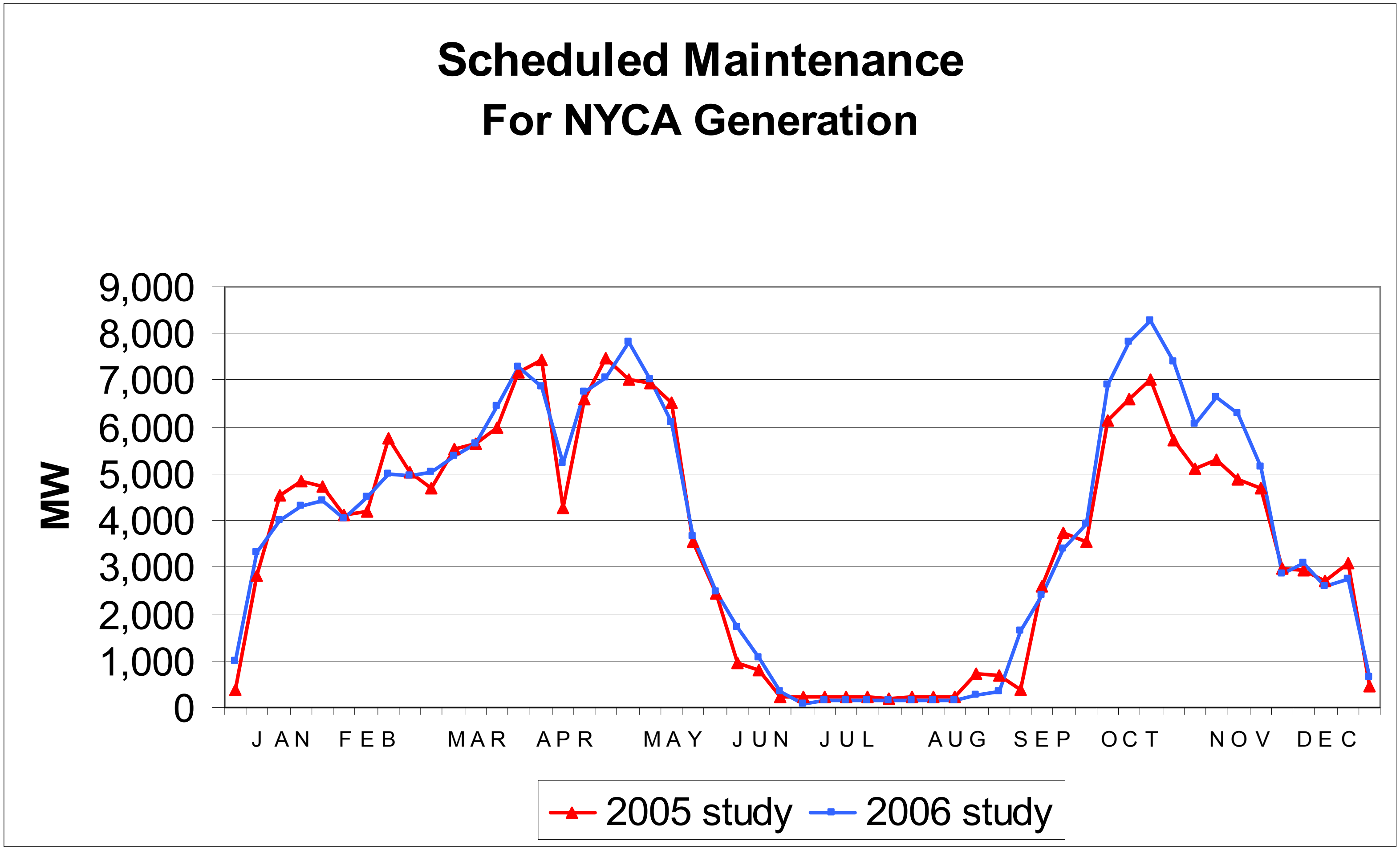


Figure A-9 shows the amount of capacity assumed to be scheduled out in the 2005 and 2006 studies.

The planned outages in the current study over the 2006 summer period are approximately 150 MW.

Figure A-9


Scheduled Maintenance
For NYCA Generation
MW
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
2005 study
2006 study

Combustion Turbine Units. Observations of combustion turbine performance over the past several years have indicated that the output of these units is limited at temperatures above design conditions. This derate has been measured as a steady value each year (80 MW per degree above 92 degrees F), and is applied directly against those units that are impacted when the load levels exceed forecast.

The derate does not affect all units because many of the new units are capable of generating up to 88 or 94 MW but are limited by permit to 79.9 MW, so they are not impacted by the temperature derating in obtaining an output of 79.9 MW. About one quarter of the existing 3,700 MW of Combustion Turbines fall into this category.

Hydro Units. The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model based on historic water flows and unit performance. The remaining 1,040 MW of hydro facilities are simulated in GE-MARS with a 45% hydro derate model, representing deratings in accordance with recent historic hydro water conditions.

Special Case Resources (SCRs) and Emergency Demand Response Program (EDRP)

Special Case Resources (SCRs) are loads capable of being interrupted, and distributed generators, rated at 100 kW or higher, that are not directly telemetered. SCRs are ICAP resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual.

The Emergency Demand Response Program (EDRP) is a separate program that allows registered interruptible loads and standby generators to participate on a voluntary basis and be paid for their ability to restore operating reserves.

GE-MARS models SCRs and EDRP as EOP steps and will activate these steps to minimize the probability of customer load disconnection. Both GE-MARS and NYISO operations only activate EOPs in zones where they are capable of be delivered.

For this year's study the NYISO has recommended that SCRs be modeled as a 1,016 MW EOP step, discounted to 935 MW in July and August (and further discounted in other months proportionally to the monthly peak load). EDRP are modeled as a 210 MW EOP step with a limit of five calls per month. This EOP is discounted based on actual experience from the forecast registered amount of 466 MW.

External Installed Capacity from Contracts

An input to the study is the amount of NYCA installed capacity that is assumed located outside NYCA. Some of this capacity is grandfathered.

Transactions

The NYISO has recommended that the following inter-area capacity transactions to be modeled in this study:

The Base Case assumes the following summer external ICAP: 55 MW from Ontario, 1000 MW from HQ, 730 MW from New England and 1300 MW from PJM. This totals 3085 MW of expected summer external ICAP. For this analysis the New England to Long Island (Cross

Sound Cable) firm transaction associated with LIPA UDR is modeled as a 330 MW ISO-NE ICAP generator with a historically determined forced outage rate connected to a tie between New England and Long Island. This tie has a 1.3% Forced Outage Rate. The expected amount of external ICAP for the winter ranges from 2360 MW to 3010 MW.

NYISO studies have indicated that the maximum external ICAP that can be purchased without impacting reliability is 3085 MW.

All firm sales are modeled as listed in the Gold Book for the year 2005.

In calculating the IRM, all sales are subtracted from the Installed capacity. Purchases are not included. The Flat Rock load modifier is added to the installed capacity number. The resultant capacity is divided by the peak load.

A-5.3 Emergency Operating Procedures (EOPS)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. The steps listed below were provided by the NYISO based on experience.

Table A-2

Emergency Operating Procedures

Step	Procedure	Effect	MW Value
1	Special Case Resources	Load relief	1,016 MW*
2	Emergency Demand Response Prog.	Load relief	210 MW
3	5% manual voltage Reduction	Load relief	172 MW
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	600 MW
5	5% remote voltage Reduction	Load relief	461 MW**
6	Curtail Company use	Load relief	11 MW
7	Voluntary industrial curtailment	Load relief	128 MW**
8	General public appeals	Load relief	13 MW
9	Emergency Purchases	Load relief	Varies
10	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW
11	Customer disconnections	Load relief	As needed

**   The SCR's are modeled as 1,016 MW, however they are discounted to 935 MW in July and August and further discounted in other months.*
** *   These EOPs are modeled in the program as a percentage. The associated MW value is based on a forecast 2006 peak load of 32,400 MW.*

The above values are based on the year 2005 results associated with a 2006 peak load forecast of 32,400 MW. The above table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency.

The amount of help that is provided by EOPs related to load, such as voltage reduction, will vary with the load level. The EOPs presented in Table A-2 were modeled in the GE-MARS program.

The value for the voluntary industrial curtailment is reduced from that used last year to reflect the increase in the customers participating in the paid programs (SCR and EDRP).

A-5.4 Transmission Capacity Model

Introduction

The NYCA is divided into 11 Zones. The boundaries between Zones and between adjacent control Areas are called interface ties. These ties are used in the GE-MARS model to allow and limit the assistance among NYCA Zones and adjacent control Areas. While the NYCA transmission system is not explicitly modeled in the GE-MARS program, a transportation algorithm is utilized with limits on the interface ties between the Areas and Zones represented in the model. Interface tie groupings and dependent interface tie limits have been developed such that the transmission model closely resembles the standard eleven-Zone NYCA model. The interface tie limits employed are developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO and refined with additional analysis specifically for the GE-MARS representation. The new topology and interface limits are shown in Figure A-10.

The interface tie limits used in the 2005 IRM study were reviewed to assess the need to update the transfer limits and topology resulting from the changes to a multi area representation for PJM and New England and to reflect results from more recent studies. The Summer 2004 and 2005 Operating Study Reports, the 2003, 2004 and 2005 Area Transmission Reviews, the Reliability Needs Assessment (RNA) in the 2005 Comprehensive Reliability Planning Process, and the 2005 Hudson Valley Voltage Analysis Report were reviewed to update the transfer limits. Databases from the 2005 RNA were also used in the assessment. When the results in the above reports were not sufficient to make an assessment, additional analysis was done with these databases, and/or other studies were referenced.

Changes in Topology and Interface Limits

The 2006 Study is the first to employ multi-area representations for PJM and ISO-New England. These representations were provided by and reviewed with staffs from the respective ISOs and changes were made to the transmission model to reflect this employment. The changes are summarized in Table A-3.

The interface limits that impact the calculation of LOLE in the GE-MARS simulations the most are the interfaces into NYC and Long Island and the interfaces that limit flows into them, namely UPNY/SENY and UPNY/CONED. These interfaces are also the ones that required the most significant changes.

Changes in Thermally Limited Interfaces

The Dunwoodie South Interface (DS or I to J) thermal transfer limit is dependent on the balancing of flows on the two Dunwoodie to Rainey and two Sprainbrook to W 49th St. 345 kV cable circuits and the flows through Dunwoodie and Sprainbrook to the 138 kV system In City through the PAR controlled circuits. Balancing of these flows is highly dependent on system dispatch conditions. Since the flow imbalance can be very significant at times, the transfer limit has been historically derated by approximately 200 MWs from its maximum to maintain conservatism. The insertion of series reactors in each of the two Dunwoodie to Rainey and two Sprainbrook to W 49th St. 345 kV cable circuits will greatly increase the impedance of these circuits, and thus impact the distribution and balancing of flows on these four cables. The range of potential imbalance is actually reduced by this impedance change, thus suggesting an increase in transfer limit. In addition, there have been upgrades in the ratings of some cables in the 138 kV system that will allow increased flows through the PARS under certain conditions. However, to maintain conservatism and to reflect uncertainty in flow balancing, the thermal limit for the Dunwoodie South Interface (I to J) was maintained at 3700 MW.

Changes were also made to the interface limits from zones J and K to the adjoining control areas. These changes were made to reflect internal PJM and New England limits and to reflect those limits sensitivity to unit outages. These are summarized in Table A-3.

Changes to Reflect Voltage Constraints

Recent voltage studies for the 2005 summer period and for 2006 summer period have indicated a degradation of voltage based transfer limits in the Hudson Valley area of the NYCA. The primary interfaces affected are UPNY/SENY(Grouping), UPNY/CONED(G to H), Dunwoodie South(I to J), and Y49/Y50(I to K). The impacts on these interfaces are discussed below.

- **UPNY/SENY** A reduction of 100 MWs was done to the initial transfer limit as well as the transfer limits for the unit sensitive nomograms with Athens.

- **UPNY/CONED** This interface limit was reduced from 5600 MW to 5000 MW to reflect voltage constraints that are the result of upstream constraints, continued load growth in the Hudson Valley, and network changes. The upstream constraints are UPNY/SENY and the flows into and out of Ramapo.

  This interface is further impacted by unit outages both upstream and downstream from it. Although its limit is impacted by the outage of downstream units, this effect does not need to be implemented because the impact is positive (Indian Point 2 and 3) and less than the MWs lost by the unit outage. Therefore, the impact on LOLE is captured by the upstream constraint and the capacity loss. For units upstream of this interface, the sensitivity to unit outages is critical because there is both a MW capacity lost between a potential UPNY/SENY upstream constraint and a reduction in transfer limits downstream. Based on the unit sensitivity analysis, this impact was modeled as a reduction of 300 MW for any of the Roseton and Bowline units.

- **Dunwoodie South and Y49/Y50** These two interfaces limit capacity flow into NYC and Long Island. They both share the capacity flow coming from upstate New York and thus were grouped to reflect their simultaneous nature. The grouping limit is initially the sum of the individual interface limits. This limit is reduced by 300 MW when loads are above 90%. Studies indicated that there is not an equivalent impact on the grouping limit by the flows on Dunwoodie South versus Y49/Y50. This will impact the limit of one component interface when the required flow on the other interface is below its limit.

  The relative impact on the grouping limit by the component interface flows was found to be two thirds for Y49/Y50. In other words, for every 300 MWs that are not needed on Y49/Y50, an additional flow of 200 MW can be made on Dunwoodie South, up to its individual limit. This grouping limit and derivation are summarized below in Table A-3. Studies have indicated that this limit is sensitive to unit outages. This sensitivity is discussed below.

  The transfer limit already represents the contingency loss of Ravenswood 3. With additional capacity In City and the cable charging present in the city, it was assumed that after the loss of Ravenswood 3, there would be sufficient MW and MVAR capability in the city that could be dispatched to make up for the contingency loss. This means that the lower limit based on the contingency loss of Ravenswood 3 would be appropriate for the Ravenswood 3 unavailable state (or after the system was restored to the normal state following the contingency loss of Ravenswood 3), so that no dynamic rating based on Ravenswood 3 availability was required. A dynamic rating based on the availability of the existing Poletti unit was necessary because of the large size of the Poletti unit and its proximity to the Ravenswood 3 unit in the 345 kV system. Its unavailability would exacerbate the contingency loss of Ravenswood 3, and thus a dynamic rating was developed to reflect the unavailability of Poletti.

For the simultaneous unavailability of Ravenswood 3 and Poletti, (a condition not studied in detail), it was assumed that the probability of simultaneous outage of both units coupled with enough other capacity outages to result in an LOLE state was very low. It was also assumed that when both Poletti and Ravenswood 3 are on outage, the series reactors would be switched out, eliminating the need for further transfer limit reductions for unit outages. However, since operational procedures direct that this reactor switching is preferably done while the cable loadings are low, there is an impact for the in day period when the simultaneous outage of Poletti and Ravenswood 3 occurs. This in day occurrence has such a low probability that its impact on IRM can be ignored, as explained below.

Several indications show that this simultaneous impact is not a consequential problem in the GE-MARS analysis.   A review of the transition rates used for Ravenswood 3 and its mean times in states indicates that any inaccuracy introduced is very small, effecting no more than 5% of days when Ravenswood is unavailable. Poletti transition rates would demonstrate something similar, resulting in an extremely low probability of simultaneous outage initiating in day. It is unlikely, therefore, that this issue can appreciably affect the IRM study's results.

Table A-3 Interface Limit Changes for 2006 IRM

Interface Name		2005 Limit	2006 Limits, Base Case	Comments
PJM Interfaces		One Area	Updated to Three Area	New Multi Area Topology
PJM East to G	+	1100	500	Reflects Internal PJM Constraints
	-	2000	2000	
PJM East to J	+	1000	600 – 1200, PJM unit	Reflects Internal PJM Constraints
	-	0	0	
J to K, CE-LIPA	+	250	175	Joint Con Ed and LIPA Update
	-	420	420	
SWCT to K	+	286	New Eng Unit Sensitive	LIPA-ISONE Udate
	-	286	286	
New England Interfaces		One Area	Updated to Five Area	Comments
				New Multi Area Topology
Updates to Transfer Limits to Reflect Hudson Valley Voltage Studies				
UPNY/SENY Group	+	5100,Athens	5000,Athens Sensitive	Reduced by 100 MW
	-	1999	1999	Not Unit Sensitive for voltage
UPNY/CE	+	5600	5000	Reduced to 5000 MW, Interface
	-	1999	1999	Grouping and Unit&Load Sensitive
G toH, UPNY/CE Interface Group			6000	New Grouping to Limit Flows to
				PJM with High UNY/CE Flows
I to J, or DS	+	3700	Limited in Grouping	I to J and I to K Grouped into
	-	1999		DSY49/Y50 Rated at 4970
I to K, or Y49/Y50	+	1270	Limited in Grouping	Reduces to 4670 MW, Load > 90%
	-	530		Reduces to 4570, Poletti Outage

- DSY49Y50 or, I to J and I to K starts with ratings of 4,970 and 2,530 MW, and UPNY-CONED starts with ratings of 5,000 and 1,999 MW

- If the unadjusted forecast load in G > 1,927 and H > 532 and I > 1,549 and J > 10,355, the DSY49Y50 ratings change to 4,670 and 2,530

- If the above load conditions are met and POLETI is unavailable, the DSY49Y50 ratings change to 4,570 and 2,530 MW

- If the unadjusted forecast load in G > 1927 and H > 532 and I > 1,549 and exactly one of the four units (ROSTN1, ROSTN2, BWLNS1, BWLNS2) is unavailable, the UPNY-CONED ratings change to 4,700 and 1,999 MW

- If the unadjusted forecast load in G > 1927 and H > 532 and I > 1,549 and exactly two of the four units (ROSTN1, ROSTN2, BWLNS1, BWLNS2) are unavailable, the UPNY-CONED ratings change to 4,400 and 1,999 MW

Derivation of DSY49/Y50 Interface Grouping Limits:

For the initial conditions

DS + Y4950 + 1/3 (1270 - Y4950) = 4970

DS + 2/3(Y4950) + 1270/3 = 4970

3*DS + 2*Y4950 + 1270 = 14,910

3*DS + 2*Y4950 = 13,640

For the first condition set:

DS + Y4950 + 1/3 (1270 - Y4950) = 4670

DS + 2/3(Y4950) + 1270/3 = 4670

3*DS + 2*Y4950 + 1270 = 14010

3*DS + 2*Y4950 = 12,740

For the second condition set:

DS + Y4950 + 1/3 (1270 - Y 49) = 4570

DS + 2/3(Y4950) + 1270/3 = 4570

3*DS + 2*Y4950 + 1270 = 13710

3*DS + 2*Y4950 = 12,440

Cable Interfaces

Failure rates for overhead lines and underground cables are similar but the repair time for an underground cable is much longer. Therefore, forced transmission outages are included in the GE-MARS model for the underground cable system from surrounding Zones entering into New York City and Long Island. The GE-MARS model uses transition rates between operating states for each interface, which are calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface are calculated based on the individual make-up of each interface, which includes failure rates and repair times for the cable, and for any transformer and/or phase angle regulator on that particular cable.

For the Con Edison system, the transition rates were calculated based on historical failures of the entire Consolidated Edison's underground cables, transformers, and phase angle regulators that are the three major components of the cable interface system into New York City. The failure rates and repair rates for transformers, and phase angle regulators were calculated by voltage classification, and the cables' failure rates and repair rates were calculated by voltage classification and on a per-mile basis. Typically, the larger the cable and equipment population included in the study, the better the results are in predicting the future performance of the underground electric system. Once a failure rate and a repair time are created for each component, they are combined to form a single cable system model for each cable. Each single cable system model is then combined together with the other single cable system models that make-up that particular interface to obtain a composite interface model. This provides a conservative estimated transition rate for each of the three cable interfaces into New York City.

The EFORd calculated from the transition rates of the three transmission interfaces into New

York City reveal a slight decrease in the availability of all three interfaces.

On the other hand, the Long Island interface showed a significant increase due to the availability increase of feeders Y49 and Y50 that tie Long Island with Area I.

Interconnection Support During Emergencies

Base case assumptions considered the full capacity of transfer capability from external Control Areas (adjusted for grandfathered contracts and estimated external capacity purchases) in determining the level of external emergency assistance.

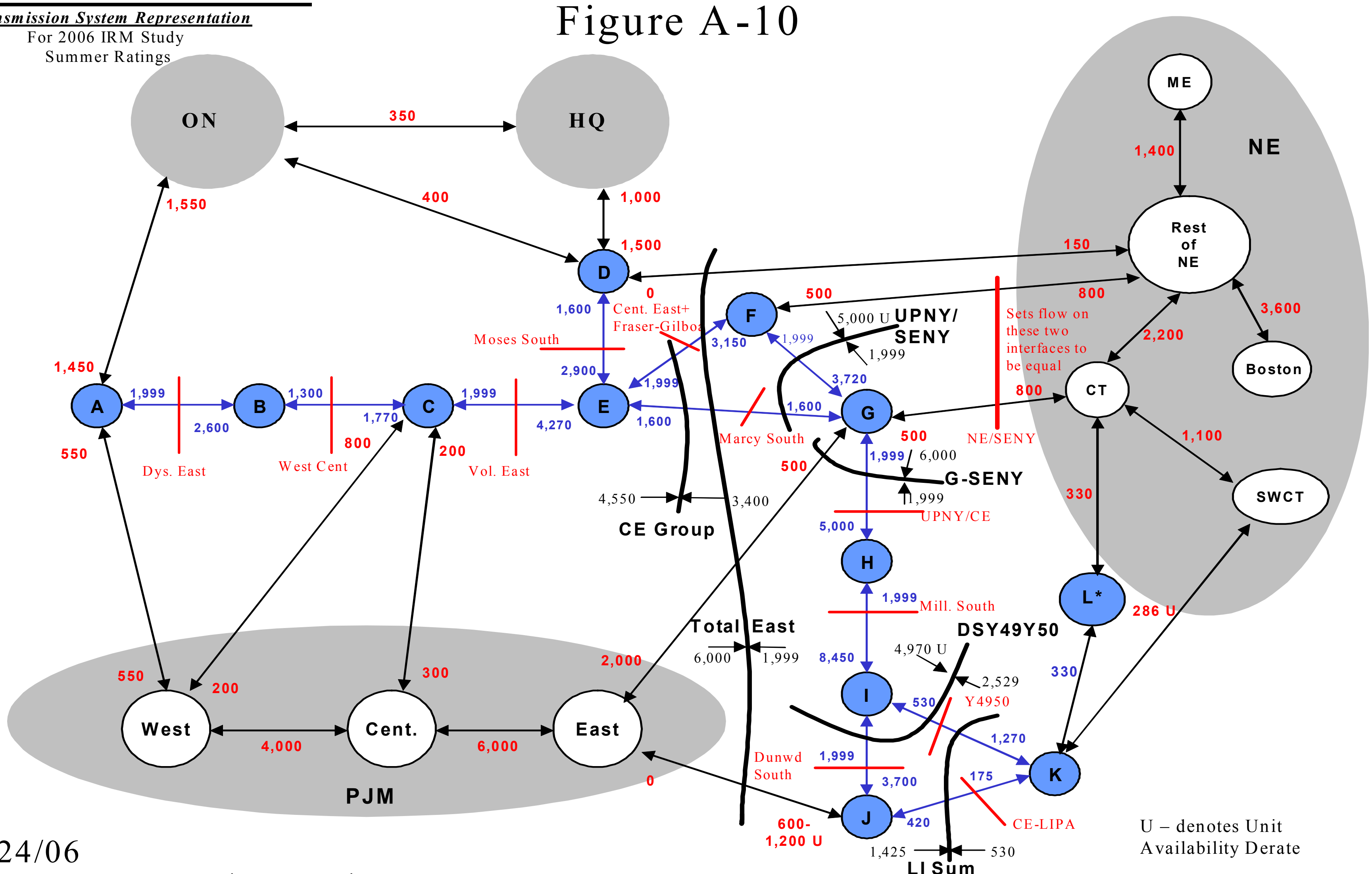
New York Control Area

Transmission System Representation

For 2006 IRM Study

Summer Ratings

Figure A-10



1/24/06

*New York Dummy zone

A-5.5 Locational Capacity Requirements

The GE-MARS model used in the IRM study provides an assessment of the adequacy of the NYCA transmission system to deliver assistance from one Zone to another for meeting load requirements. Previous studies have identified transmission constraints into certain Zones that could impact the LOLE of these Zones, as well as the statewide LOLE. To minimize these potential LOLE impacts, these Zones require a minimum portion of their NYCA ICAP requirement, i.e., locational ICAP, which shall be electrically located within the Zone in order to ensure that sufficient energy and capacity are available in that Zone and that NYSRC Reliability Rules are met. Locational ICAP requirements are currently applicable to two transmission-constrained Zones, New York City and Long Island, and are normally expressed as a percentage of each Zone's annual peak load.

These locational ICAP requirements, recognized by NYSRC Reliability Rule A-R2 and monitored by the NYISO, supplement the statewide IRM requirement. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A-5.6 Outside World Load and Capacity Models

NYCA reliability largely depends on emergency assistance from its interconnected Control Areas in NPCC and PJM, based on reserve sharing agreements with the Outside World Areas. Load and capacity models of the Outside World Areas are therefore represented in the GE-MARS analyses. The load and capacity models for ISO-NE, IMO, PJM, and Hydro-Quebec are based on data received from the Outside World Areas, as well as NPCC sources.

The primary consideration for developing the final load and capacity models for the Outside World Areas is to avoid overdependence on the Outside World Areas for emergency capacity support. For this purpose, a rule is applied whereby either an Outside World Area's LOLE cannot be lower than 0.100 days/year LOLE, or its isolated LOLE cannot be lower than that of the NYCA. In other words, the neighboring Areas are assumed to be equally or less reliable than NYCA. Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within the Outside World Areas that may limit emergency assistance to the NYCA. This recognition is considered implicitly for those Areas that have not supplied internal transmission constraint data.

The year 2002 is used in this study for both the NYCA and the Outside World Area load shapes. In order to avoid overdependence from emergency assistance, the three highest summer load peak days of the Outside World Areas' are modeled to match the same load sequence as NYCA.

The Ontario and Hydro Quebec Area representations are based on the models provided for the NPCC study titled "Summer 2001 Multi-Area Probabilistic Reliability Assessment" dated May 2001 (CP-8).

This year both New England and PJM are represented as multi area models for the first time. These models are based on data provided by them.

The EOPs were removed from the ISO-NE and IMO models (the only ones other than New York that explicitly modeled EOPs) to avoid the difficulty in modeling the sequence and coordination of implementing them. This is a conservative measure.

The assistance from East Central Area Reliability Council (ECAR) and the Maritime Provinces was not considered, therefore, limiting the emergency assistance to the NYCA from the immediate neighboring control areas. This consideration is another measure of conservatism added to the analyses.

The load forecast uncertainty model for the outside world model is from the CP-8 study.

A-6 Assumption Summary -Comparison of Assumptions Used in the 2005 Study and 2006 Study

While some of the following assumptions have not been updated, they have all been reviewed to be sure that they are still current and appropriate.

Base Case Assumption	**2005 Study**	**2006 Study**
NYCA Capacity	All Capacity in the NYCA	All Capacity in the NYCA
NYCA Unit Ratings	Based on 2004 Gold Book	Based on 2005 Gold Book
Planned Capacity	Updated to time of study	Updated to time of study
Forced and partial outage rates	NERC-GADS 1999-2003 plus a 711 MW DMNC derating.	NERC-GADS 2000-2004 plus a 125 MW DMNC derating.
Planned outages	Based on schedules received by NYISO as of Sept. 2003 & adjusted for history	Based on schedules received by NYISO as of Sept. 2004 & adjusted for history
Non NYPA hydro modeling	45% derating	45% derating
Unit Maintenance Schedule	Historic adjusted for forecasted time of year	Historic adjusted for forecasted time of year
Neighboring Control Areas – Ontario and HQ	NPCC CP-8 2001 Study	NPCC CP-8 2001 Study
Neighboring Control Area – New England	NPCC CP-8 2001 Study	New multi area model based on data from New England
Neighboring Control Area – PJM	Developed from public information	New multi area model based on data from PJM.
Load Model	Base Case NYCA 2002 shape	Base Case 2002 NYCA shape
Peak Load Forecast	Gold Book forecast of 32,320 MW	Gold Book forecast of 32,400 MW
Load Forecast Uncertainty	Includes improved uncertainty model that models three Areas of NYCA separately	Includes improved uncertainty model that models three Areas of NYCA separately
External ICAP	2755 M Total, 55 from Ontario, 1200 from HQ, 400 from NE and 1100 from PJM	3085 MW Total, 55 from Ontario, 1000 from HQ, 730 from NE, and 1300 from PJM
Emergency Operating Procedures	1874 MW load relief (Includes 877 MW SCRs and 269 MW EDRPs)	1930 MW load relief (Includes 935 MW SCRs and 210 MW EDRPs)
Locational ICAP Levels	Assure Base Case results meet or exceed the minimum levels of the 2004 NYISO Locational Requirements Study.	Locational ICAP Levels are identified at various IRM levels from this study.
Transfer Limits	2004 NYISO Assessment	2005 NYISO Assessment

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APPENDIX B

DETAILS OF STUDY RESULTS

B-1 Introduction

Appendix B provides details of the GE-MARS case results referenced in the body of this report. This includes results of the anchor point case and various sensitivities cases, as well as an analysis of emergency operating procedures for the anchor point case required IRM.

B-2 Base Case and Sensitivity Case Results

Table B-1 summarizes the 2006 capability year IRM requirements under anchor point case assumptions, as well as under a range of assumption changes from this case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the anchor point case required IRM would change for assumption modifications, either one at a time, or in combination.

TABLE B-1
Study Sensitivity Results
For Non-UDR case

Case			LOCATIONAL	
No.	DESCRIPTION	IRM	J	K
1	NYCA Isolated*	23.2%	86.0%	104.1%
2	No SCRs or EDRP	22.7%	85.7%	104.4%
3	No Voltage Reductions	19.6%	83.5%	101.2%
4	No Internal NYCA Transfer Limits**	15.5%	80.6%	98.0%
5	External Area IRM reduced 10 %	18.6%	83.9%	100.5%
6	External Area IRM increased 10 %	11.1%	77.5%	95.2%
7	Decrease GADf to 0 MW	17.2%	81.8%	99.3%
8	Increase GADf 10 250 MW	17.8%	82.3%	99.8%
9	No Wind Generators	17.4%	82.0%	99.5%
10	3:2 Y-50:Y49 Balance	17.5%	82.0%	99.5%

* With UDRs modeled for the Sound Cable Crossing, the isolated IRM is 23.8%
** With UDRs modeled for the Sound Cable Crossing, the IRM requirement is 15.7%.

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1days/year criterion. In the base case, the study shows that approximately 1.2 remote voltage reductions per year would be implemented to meet the once in 10 years disconnection criterion. The expected frequency for each of the EOPs for the -UDR Base Case is provided in Table B-2.

TABLE B-2
Implementation of Emergency Operating Procedures *
Anchor Point Case Assumptions (IRM = 18.0%)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	3.3
Require EDRPs	2.2
5% manual voltage reduction	2.0
30 minute reserve to zero	2.0
5% remote control voltage reduction	1.2
Curtail Company use	0.8
Voluntary load curtailment	0.8
Public appeals	0.7
Emergency purchases	0.7
10 minute reserve to zero	0.3
Customer disconnections	0.1

* See Appendix A, Table A-2